Longleaf CCS Hub

Longleaf CCS, LLC

Application Narrative

40 CFR 146.82 (a)

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Locations: Mobile County, Alabama

LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W

LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W

LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W

LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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Injection zone: stratigraphic units between the base of the primary confining zone and the top of the lower confining zone.

Injection interval: formation where CO_2 will be injected.

List of Acronyms

AoR	Area of Review
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response Plan
ft	Feet
GSA	Geological Survey of Alabama
HPF	Hatters Pond Fault
LL	Longleaf
MASP	Maximum allowable surface pressure
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mol%	Percentage of total moles in a mixture made up by one constituent
msl	Mean sea level
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
NMR	Nuclear Magnetic Resonance
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
ppmv	Parts per million volume
psi	Pounds per square inch, gauge
psia	Pounds per square inch, absolute
psi/ft	Pounds per square inch per foot
RCA	Routine core analysis
SGR	Shale gouge ratio
SS	Sub- Sea
TD	Total Depth
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. PROJECT BACKGROUND AND CONTACT INFORMATION

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

A.1. The Longleaf CCS Hub

Longleaf CCS, LLC, an affiliate of Tenaska, Inc. (Tenaska) is proposing development of an industrial scale carbon capture and storage (CCS) hub in Mobile County, Alabama. The Longleaf CCS Hub ("the project") area is located 27 miles north of the city of Mobile, Alabama and 8 miles east of the city of Citronelle, Alabama (**Figure 1**). The center of the project area is located 6 miles northwest of Alabama Power's James M. Barry electrical generation plant (Plant Barry), a major 2.6-Gigawatt capacity electric power generating plant and one of the possible sources of CO_2 for the project. The Longleaf CCS Hub covers a 58,000-acre (90-square mile) area located east of the Mobile Graben and west of the Citronelle Dome, two prominent geologic features in this area (**Figure 2**). The project is seeking to permit and drill up to four injection wells, five in-zone monitoring wells, two above-zone monitoring wells, and four deep underground source of drinking water (USDW) monitoring wells. These wells will be drilled on ten well pads. Shallow groundwater monitoring wells (not shown) will be drilled on nine of the well pads. The location of each well pad and its associated injection and/or monitoring well is shown in **Figure 2**.

The area surrounding the project contains both shallow water supply wells and deeper wells related to oil and gas production and wastewater disposal. However, within the project's area of review (AoR), there are only shallow water wells. The location of these shallow water wells within the AoR are shown in **Figure 2.** The well number, latitude, longitude, well type (i.e., public, domestic), and depth of the 6 water supply wells within the AoR are provided in **Table 1**.

There are several notable surface features in and around the project area. **Figure 2** shows the location of all surface bodies of water, city limits for the cities of Citronelle and Mt. Vernon, numerous roads, land containing residential buildings, the MOWA Choctaw State Reservation tribal boundary three miles north of the AoR, the Chastang Landfill adjacent to the eastern boundary of the AoR, and Plant Barry. There are no springs, state or EPA subsurface cleanup sites, surface or subsurface mines, or quarries identified in and around the AoR.

The subsurface within and around the AoR has been well studied, initially from oil and gas resource development assessments (Eaves, 1976; Mancini and Benson, 1985; Mancini et al., 1985; Esposito and King, 1987; Mancini et al., 1987; Bolin et al., 1986; Raymond, 1995; Pashin et al., 2000; Kopaska-Merkel, 2002). More recent investigations, conducted as part of the DOE/NETL and Southern States Energy Board sponsored "Integrated Anthropogenic CO_2 Storage Project" targeted the deep saline Paluxy Formation at the Citronelle Dome, located west of the project area. This work, along with the prior studies noted above, have shown that the area has attractive geologic properties and large potential for safely and permanently storing CO_2 in the deep saline reservoirs below the project area. (Esposito et al., 2008; Pashin et al., 2008; Esposito et al., 2010; Koperna et al., 2012).

No depth waiver or aquifer exemption is requested for the project since the proposed injection interval is 8,750 feet deeper than the deepest USDW in the area and the reservoir fluid in the proposed injection interval is highly saline, with total dissolved solids (TDS) greater than 100,000 mg/L.

Monitoring protocols have been designed to allow Longleaf CCS, LLC to track the areal and vertical extent of the CO_2 plume, the development of the elevated pressure front, and changes in pressure, saturations, and fluid composition above the confining zone. These protocols will also provide input data to periodic reevaluation of the AoR through computational modeling of CO_2 plume and reservoir pressures as well as changes in above injection interval conditions to ensure containment of the injectant CO_2.

The project will provide safe, secure, and long-term CO_2 storage for CO_2 emissions from key sources including the above noted Plant Barry, as well as the Williams Gas Processing Facility and the AM/NS Calvert Steel Finishing Plant. In future years, the project could also provide a viable storage option for CO_2 captured from other industrial facilities in the region.

A.2. Proposed CO_2 Source and Mass/Volume of Injection.

The three sources of CO_2 for the project are estimated to provide up to 5 Mt of captured CO_2 per year for 30 years (150 Mt total). The four injection wells will be capable of storing 13,700 metric tons / day, which is equivalent to 90% of the total emissions from the above three sources over 30 years.

A.3. Project Scope and Timeframe

The characterization of the project draws on the prior logging and core analyses work at the DOE/NETL SECARB Phase III Anthropogenic Test Site at Citronelle conducted from 2011 through 2018. This work has been supplemented by additional log analyses and seismic assessments for the project.

Four proposed injection wells will be permitted and drilled in the center of the project with each well located approximately 1.25 miles apart. Computational reservoir modeling work shows that the four injection wells will be able to safely inject the proposed volume of CO_2 provided from Plant Berry and the other four sources.

Longleaf CCS, LLC will initiate injection upon receiving EPA approval for operation of the well. It is anticipated that the 30-year injection period will start in approximately 2025, end in 2055, and be followed by a 20-year post-injection site care period, taking the project to 2075.

A.4. Partners/Collaborators/Stakeholders

Tenaska has made major, corporate-level commitments toward the development of the project. Tenaska is a privately held, independent power company based in Omaha, Nebraska. Established in 1987, Tenaska has a generating fleet over 7,500 MW, is one of the largest gas marketing companies in North America and has balance sheet equity of $2.9 billion. Longleaf CCS, LLC, an affiliate of Tenaska, will serve as the project owner and will assume liability for the project development, finance, and operation. The project will be conducted entirely within the State of Alabama in Mobile County. No tribal or territory boundaries will be impacted per 40 CFR 146.82(a)(20). The key contacts are:

Longleaf CCS, LLC
Ryan Choquette, Sr. Project Manager
Project Mailing Address:
Tenaska Inc, 14302 FNB Parkway, Omaha, NE 68154
402-938-1641, Rchoquette@Tenaska.com

Advanced Resources International, Inc.
Vello A. Kuuskraa, President
Advanced Resources International, 4501 Fairfax Dr., Suite 910, Arlington, VA 22203
703-528-8420, vkuuskraa@adv-res.com

The State of Alabama Oil and Gas Board
Berry H. (Nick) Tew, Jr., State Geologist & Oil and Gas Supervisor
AL OGB - Tuscaloosa, 420 Hackberry Lane, Tuscaloosa, AL 35401
205-247-3679, ntew@gsa.state.al.us

A.5. Other Permit Information Required Under 40 CFR 144.31(e)

<u>Applicable SIC Codes</u>

Per ***40 CFR 144.31(e)(3)***, the SIC codes applicable to the Longleaf CCS Hub are:

1. 49530300 Nonhazardous waste disposal sites – primarily engaged in collection and disposal of refuse by processing or destruction or in operation of incinerators/waste treatment plants/landfills/other sites for disposal of such materials.
2. 51690203 Carbon Dioxide – primarily engaged in wholesale distribution of CO_2
3. 4619 Pipelines, not elsewhere classified – primarily engaged in pipeline transportation of commodities except petroleum and natural gas.

<u>Permits and Authorizations</u>

The permits and authorizations under ***40 CFR 144.31(e)(6)*** that will likely be required for the wells at the Longleaf CCS Hub, the permit/authorization jurisdictions, and the associated project development activities are provided in **Table 2**.

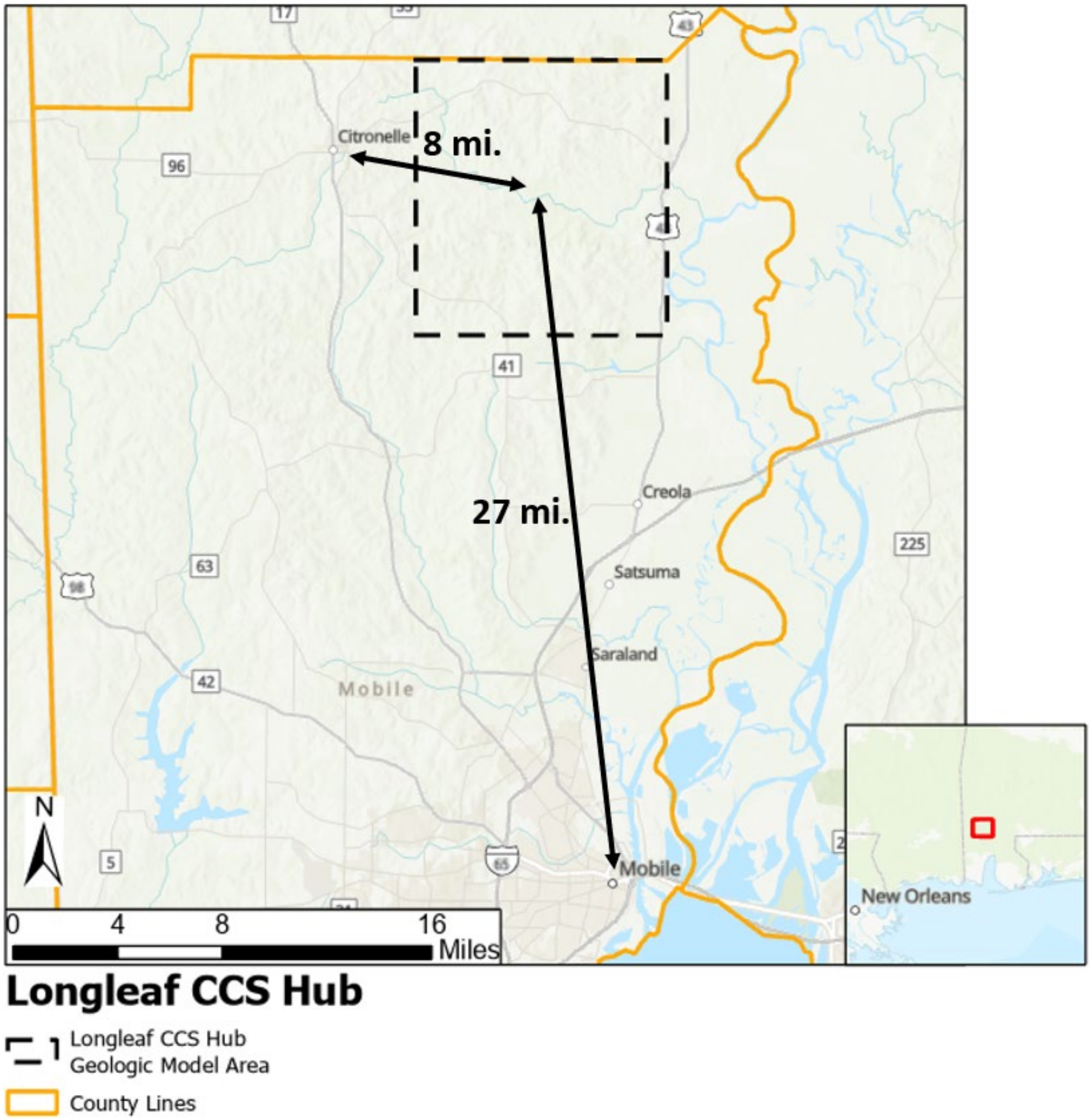


Figure 1. Location of the Longleaf CCS Hub in Southwestern Alabama.

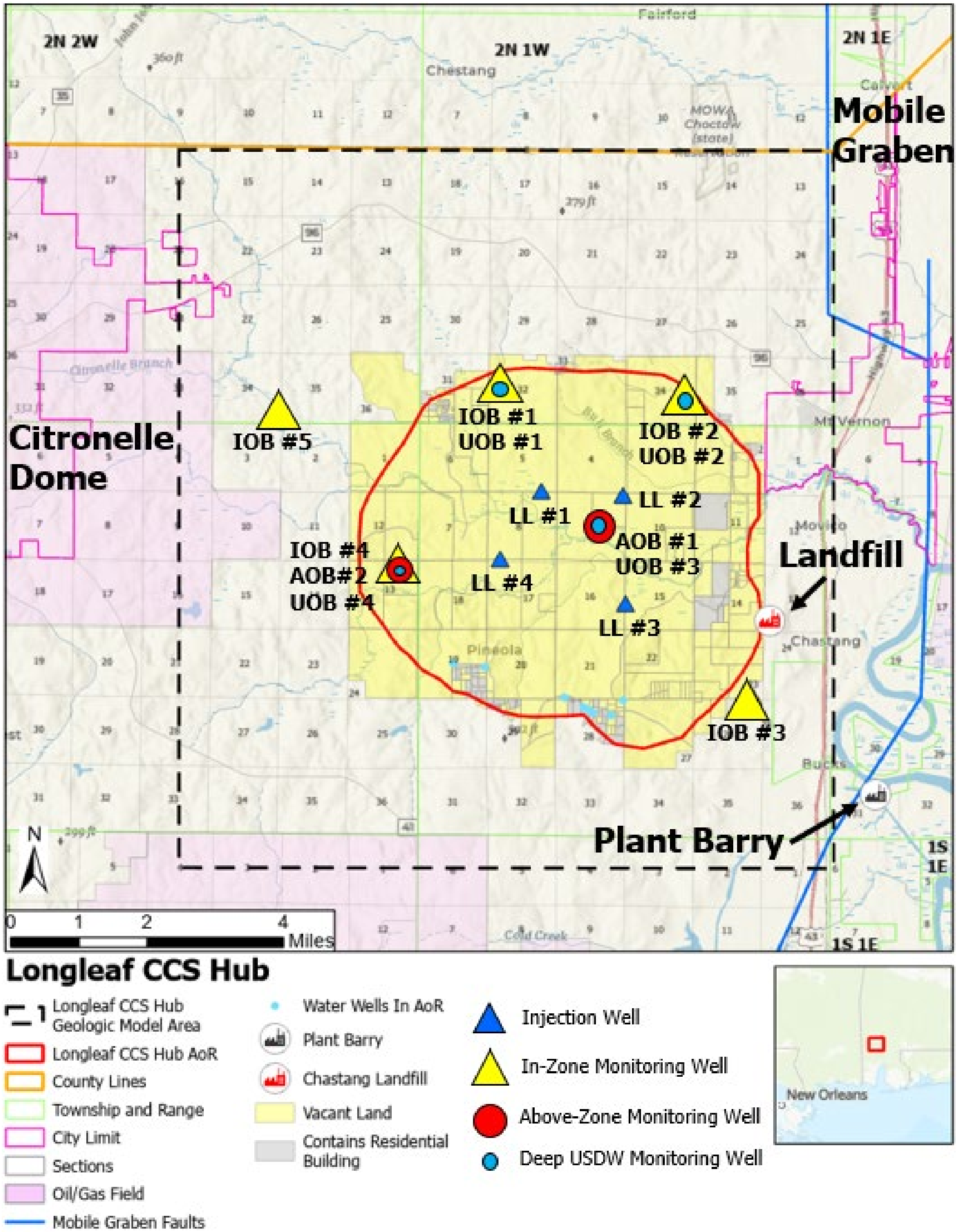


Figure 2. Surface feature map of the Longleaf CCS Hub and its AoR. Well spots with multiple symbols will have co-located wells on the same well pad.

Table 1. List of Shallow Water Wells within the Longleaf CCS Hub AoR.

Well Name	Type	Latitude	Longitude	Well Depth (ft)
097I28004	Domestic	31.02662	-88.073916	95
097I19001	Domestic	31.03413	-88.1161078	140
097I28005	Domestic	31.0247	-88.0824543	145
097I28007	Domestic	31.02344	-88.0770718	63
097I28006	Domestic	31.02393	-88.081495	115
097I21001	Domestic	31.02730	-88.0885148	120
097I20001	Domestic	31.03346	-88.108117	90
097B35001	Domestic	31.08952	-88.0484472	125

Table 2. Permits and authorizations to be obtained for the development of the Longleaf CCS Hub wells.

Permit/Authorization	Activity	Jurisdiction
UIC Class VI Injection Well Permit to Construct	Drilling of Injection Wells	Federal
UIC Class VI Injection Well Authorization to Inject	Injecting CO_2	Federal
Greenhouse Gas Rule Subpart RR Monitoring, Reporting, and Verification Plan Approval	Injecting CO_2	Federal
Section 404 Nationwide Permit	Temporary impacts to jurisdictional waters	Federal
State Drilling Permits	Drilling of monitoring wells	State
NPDES General Permit for Water Discharge from Construction Activities	Management of stormwater during construction	State
Mobile County Development Permit	Development of project on land within Mobile County	County

B. GEOLOGIC SITE CHARACTERIZATION

B.1. Regional Geologic Structure and Hydrogeologic Properties [40 CFR 146.82(a)(3)]

B.1.1 Data Used for Geologic Characterization

The data used to develop the geologic model of the Longleaf CCS Hub includes existing data from the DOE/NETL SECARB Phase III Anthropogenic CO_2 injection demonstration, data from nearby oil and gas resource exploration and development, and new data generated for this UIC Class VI permit application. The DOE/NETL SECARB Phase III 'Anthropogenic Test' CO_2 injection demonstration was an active resource characterization and CO_2 injection project conducted from 2011 to 2018 in the Southeast Unit of Citronelle Dome. The project injected CO_2 into the Paluxy Formation above the oil producing Rodessa Formation and used the basal shale of the Washita-Fredericksburg (Wash-Fred) interval as the confining unit (ADEM permit numbers ALSI9949664 and ALSI9949665).

Three wells were drilled as part of the Anthropogenic Test project: the characterization and observation well D-9-8 #2, the injection well D-9-7 #2, and a backup injection well D-9-9 #2 (**Figure 3**). The data collected from these wells located about ½ mile from the western boundary of the geologic model area are representative of the reservoir properties within the Longleaf CCS Hub and include a full suite of geophysical well logs including gamma ray, bulk density, dipole sonic, and porosity (**Figure 4**) and whole core. These logs were used to pick formation tops, interpret lithologies, develop synthetic seismic traces to tie depth to two-way travel time, and create 3D porosity and permeability data for the geologic model of the injection and confining zones.

One hundred eighty-six feet of whole core was collected from the Paluxy Formation, the injection interval for this permit application, in the D-9-7 #2 well, the D-9-8 #2 well, and the D-9-9 #2 well were evaluated to further define the sand-shale sequences and create porosity-permeability transforms for the Paluxy. The core samples were also used to perform mineralogical analyses such as X-ray diffraction and thin section analysis. The depths cored in each well are provided in **Table 2**.

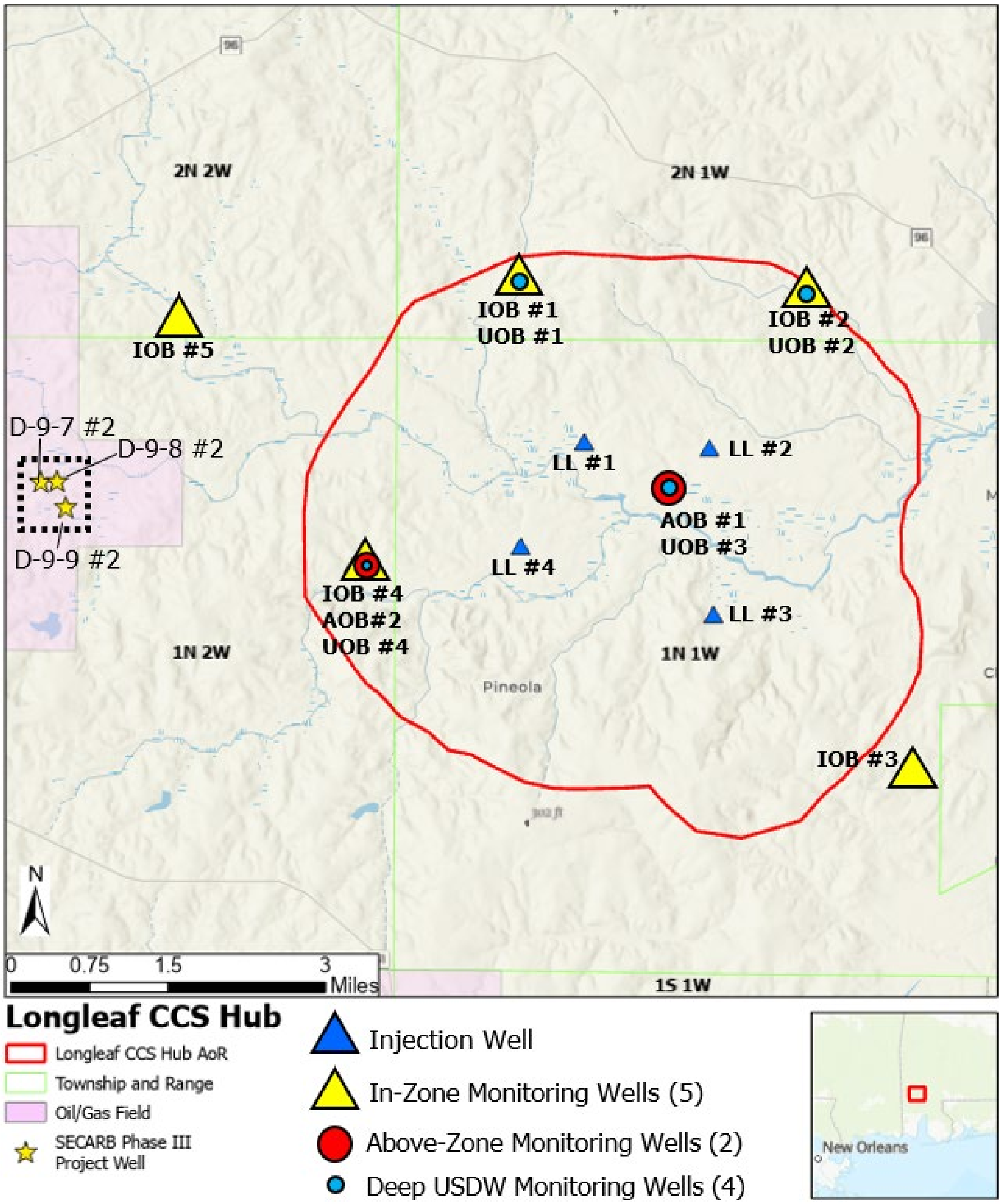


Figure 3. Map of the Longleaf CCS Hub with the location of the proposed injection and monitoring wells and the SECARB Phase III project wells

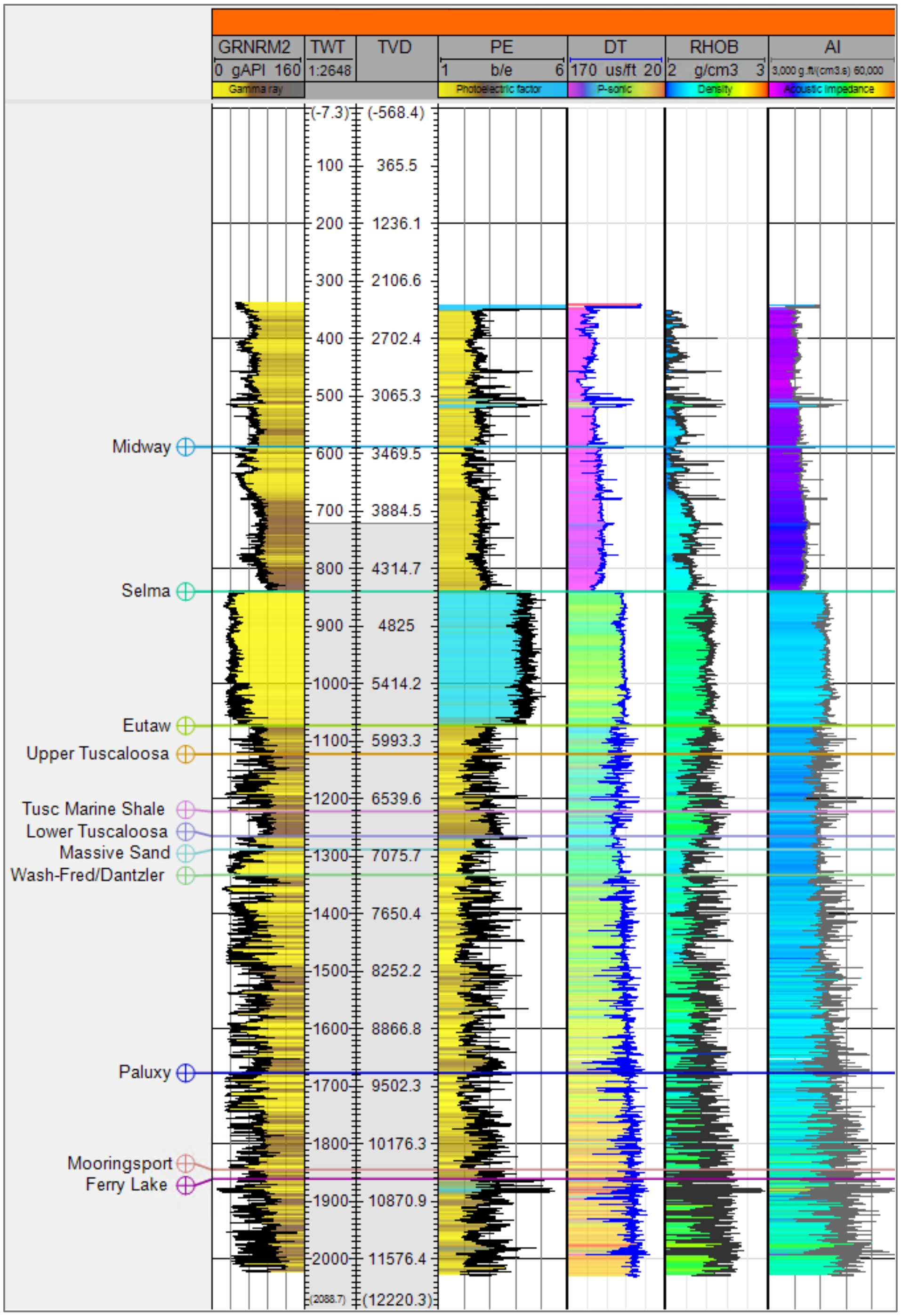


Figure 4. Geophysical logs from the D-9-8 #2 well used for site specific geologic characterization. Gamma ray is plotted in track 1, sonic is plotted in track 3, bulk density is plotted in track 4, acoustic impedance is plotted in track 5. Depth tracks shown in Two-way time (TWT) and True Vertical Depth (TVD).

Table 2. Depths of Whole Core Acquired from the SECARB Phase III Project Wells

Well	Formation Cored	Interval Cored	Retrieved Core
D-9-7 #2	Upper Paluxy Sandstone	9,568-9,636 ft.	62 Ft.
D-9-8 #2	Upper Paluxy Sandstone	9,400-9,461 ft.	53 Ft.
	Basal Paluxy Sandstone	10,430-10,465 ft.	28 Ft.
D-9-9 #2	Upper Paluxy Sandstone	9,404-9,448 ft.	43 Ft.

Reservoir fluid samples from the Paluxy Formation at the SECARB Phase III test site provided baseline geochemical characteristics including total dissolved solids (TDS), major cations and anions, dissolved carbonate-bicarbonate, and pH. Further discussion of the fluid samples gathered from the Paluxy Formation can be found in **Section B.9. Baseline Geochemical Data**.

In addition to assembling and further analyzing the wealth of reservoir characterization data gained from the DOE/NETL SECARB Phase III Anthropogenic CO_2 injection demonstration, Tenaska licensed 38.6 miles of existing 2D seismic lines that transect the Longleaf CCS Hub (**Figure 5**). This data was used to interpret site-specific and regional geologic structure, to determine lateral continuity, and build the geologic inputs used for computational modeling. The seismic data included six lines: four oriented east-west and two oriented north-south. These 2D seismic lines provided data to refine the structural interpretation of the Longleaf CCS Hub, specifically defining the structural dip and the location of the Hatters Pond Fault bounding the western edge of the Mobile Graben which is located to the east of the project area. Additionally, seismic data was used to confirm the lateral continuity of the injection and confining zones.

The 2D seismic lines were tied to sonic measurements taken in the D-9-8 #2 well (**Figure 4**) to correlate the structural interpretation of the Longleaf CCS Hub to the porosity and permeability model developed using the well log data. Together, these data sets were used to build a 3D Static Earth Model in the Petrel geological modeling software suite representative of the geologic and petrophysical characteristics within the Longleaf CCS Hub (Petrel is trademarked by and licensed from SLB Corporation). The areal extent of the 3D Static Earth Model is shown in **Figure 5**.

To provide additional data on regional structure and stratigraphy surrounding the Longleaf CCS Hub, 207 digital gramma ray logs from legacy wells were acquired and loaded into the Kingdom geologic interpretation software (Kingdom is trademarked by and licensed from S&P Global). Eighty of these logs covered the entire injection zone and primary confining unit (**Figure**

6). Well log cross sections, shown later in this application narrative, were created using a subset of these logs along with the geophysical logs from the D-9-7 #2, D-9-8 #2, and D-9-9 #2.

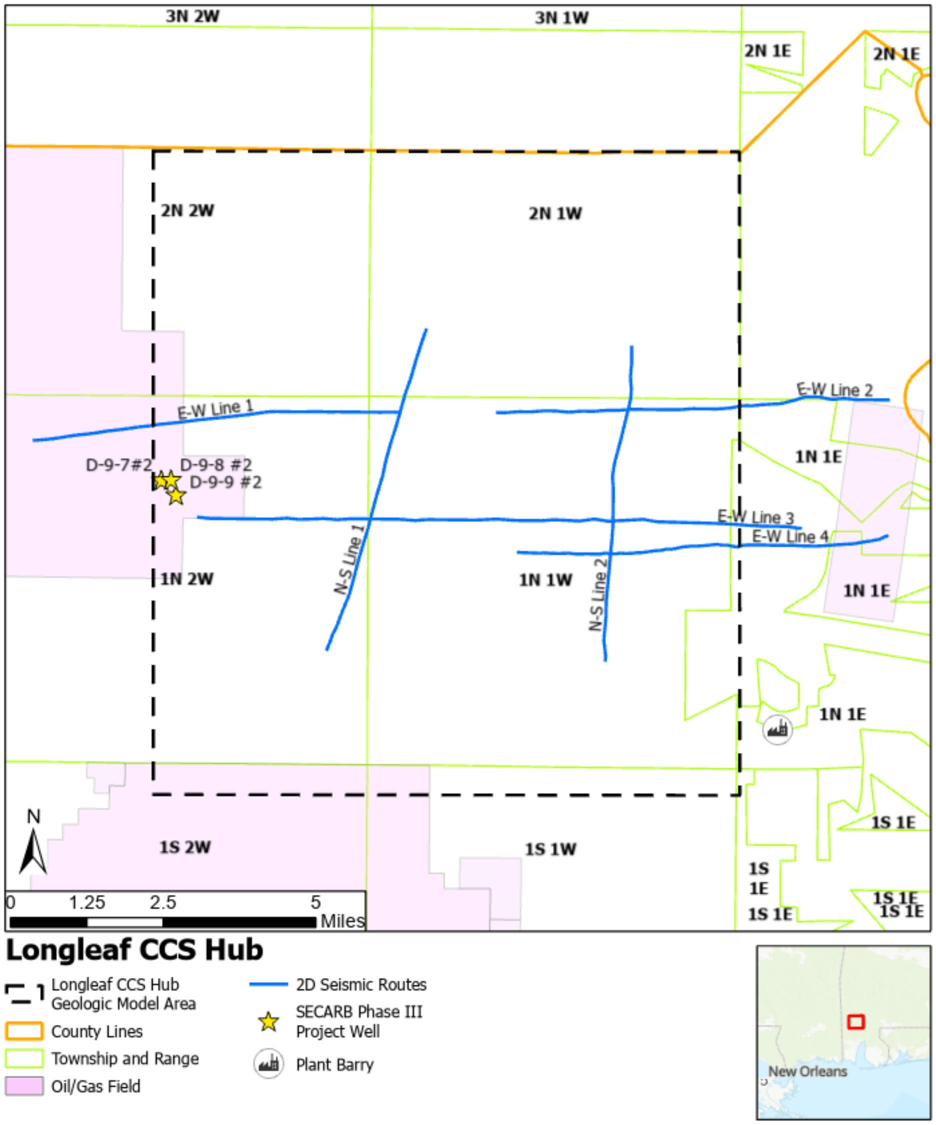


Figure 5. Map of 2D seismic coverage used to create the 3D Static Earth Model of the Longleaf CCS Hub (geologic model area indicated by black dashed line).

Acoustic logs from well D-9-8 #2 were tied to E-W Line 1 (northeastern most line) to convert time to depth.

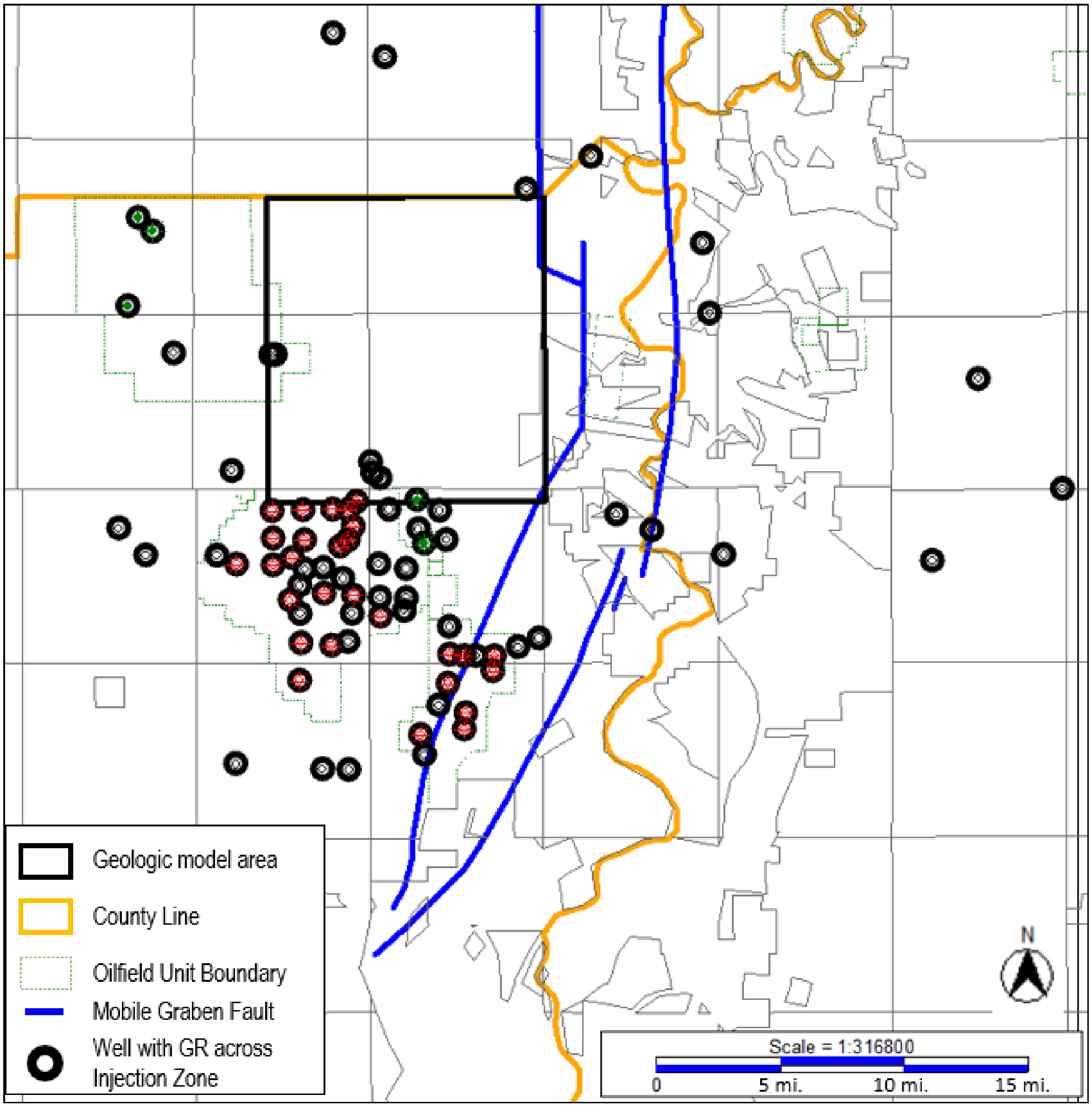


Figure 6. Wells with gamma ray logs across the Paluxy Formation and Tuscaloosa Marine Shale used in regional geologic study, including the 3 DOE/NETL SECARB Phase III Anthropogenic CO_2 injection test wells and 80 existing deep exploration wells.

B.2. Maps and Cross Sections of the Longleaf CCS Hub Model Area [40 CFR 146.82(a)(3)(i)]

B.2.1. Stratigraphic Column of the Longleaf CCS Hub

The initial CO_2 injection interval for the Longleaf CCS Hub is the lower Cretaceous Paluxy Formation. This formation contains a series of thick sandstones and interbedded mudstones and conglomerates and is located at 10,080 to 11,220 ft. subsea (10,160 to 11,300 ft below ground surface) within the Longleaf CCS Hub (**Figure 7**). The Paluxy Formation has favorable reservoir properties, such as a thick 473 ft package of porous sands giving it high storage resource potential and sufficient permeability to support high rates of CO_2 injectivity per well below 90% of the fracture pressure (See **Section B.6 Geomechanical**).

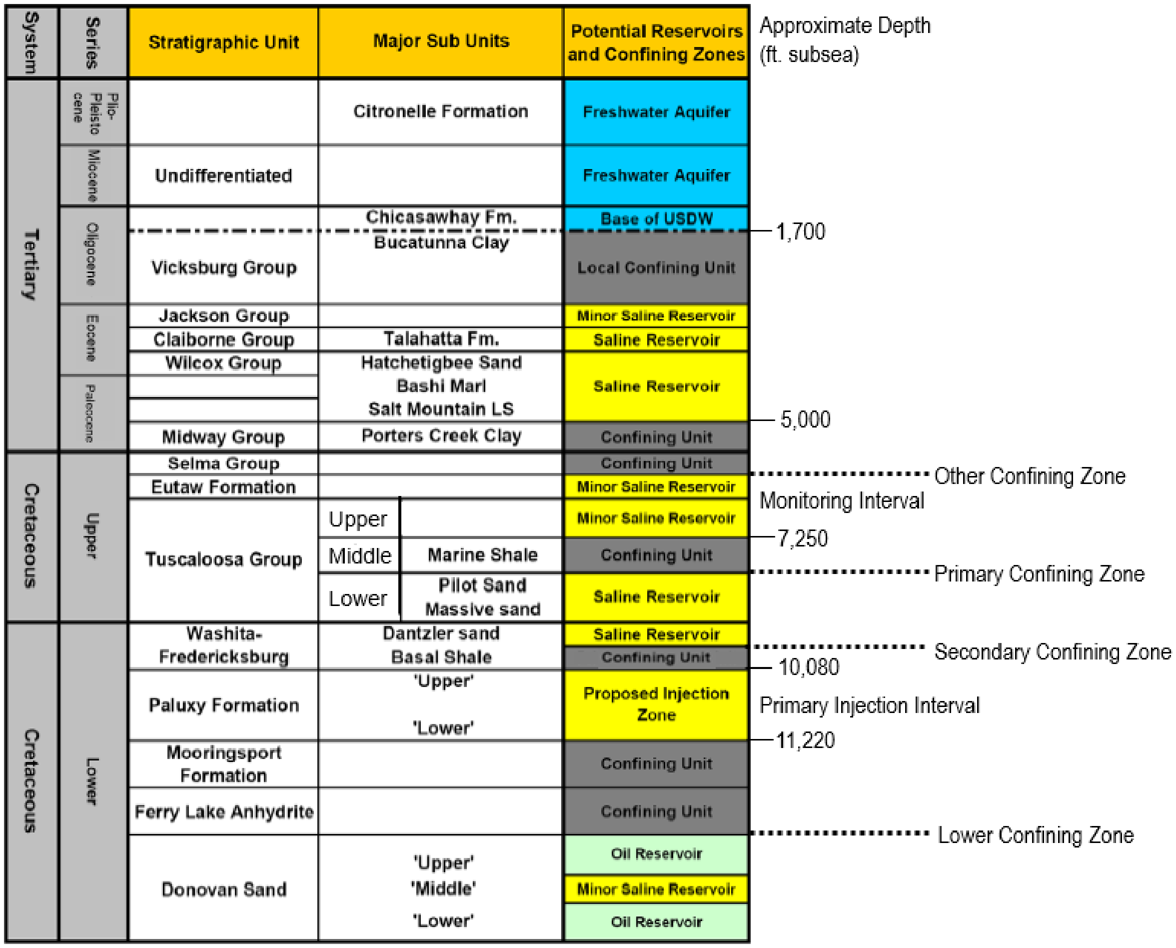
The Paluxy Formation is overlain by a 144-foot-thick transgressive shale at the base of the Washita-Fredericksburg (Wash-Fred) interval (the Basal Shale) that serves as a secondary upper confining unit for the Paluxy. Importantly, this Wash-Fred Basal Shale also served as a confining zone for the DOE/NETL SECARB Phase III CO_2 injection demonstration at Citronelle Dome (ADEM permit numbers ALSI9949664 and ALSI9949665). Beneath the Paluxy, from approximately 11,220 to 11,570 ft., is the Mooringsport Formation and the Ferry Lake Anhydrite. These two formations contain low permeability silty limestone and anhydrite, respectively, and serve as the lower confining units for the Longleaf CCS Hub.

Above the Paluxy, there is approximately 2,550 ft. of alternating sandstones and shales within the injection zone, including the Wash-Fred interval and Lower Tuscaloosa Group, that may serve as future injection intervals. The Wash-Fred and Lower Tuscaloosa have multiple internal shale baffles that may limit vertical migration of CO_2.

The injection zone is overlain by the 300-foot-thick Tuscaloosa Marine Shale (TMS) at approximately 7,250 ft subsea that will serve as the primary confining zone for the Longleaf CCS Hub (**Figure 7**). The Tuscaloosa Marine Shale is overlain by silty sandstones in the upper Tuscaloosa Group that would serve as the above zone monitoring interval for the project.

In addition to the TMS and Wash-Fred Basal Shale, the injection interval is overlain by extensive low permeability intervals that separate the lowest USDW in the Chickasawhay Formation from the Paluxy CO_2 injection interval. These include the Selma and Midway Groups at approximately 5,000 to 7,000 ft. of depth that contain a 2,000-foot-thick package of low-permeability chalks and clays (**Figure 7**).

In total, about 8,380 ft. of strata separate the top of the CO_2 injection interval in the Paluxy at 10,080 ft. and the deepest USDW, the Chickasawhay Formation, located at a depth of approximately 1,700 ft. (**Figure 7**). These formations are further described in **Table 3**.



(modified from Pashin et al., 2008)

Figure 7. Stratigraphic column identifying the storage reservoir, confining zones, and the deepest USDW addressed in this permit for the Longleaf CCS Hub.

Table 3. Formations comprising the Longleaf CCS Hub

Regulatory Interval	Formation Name	Expected Depth Interval (ft. subsea)
Other Confining Zones	Selma (chalk) / Midway (clay)	5,000–7,000
Primary Confining Zone	Marine Tuscaloosa (shale)	7,250–7,550
Secondary Confining Zone	Washita-Fredericksburg Basal Shale	9,990–10,080
Injection Interval	Paluxy Formation	10,080–11,220
Injection Interval Subunits	Upper Paluxy Sandstones	10,080–10,915
	Basal Paluxy Sandstones	10,915–11,220
Lower Confining Zone	Mooringsport (limestone) / Ferry Lake (anhydrite) Interval	11,220–11,570

B.2.2. Regional Structural Setting of the Longleaf CCS Hub

The Longleaf CCS Hub is in the eastern margin of the Mississippi Interior Salt Basin which formed during the Triassic-Jurassic rift-to-drift sequence associated with the opening of the Gulf of Mexico (Pashin et al., 2008). Structural deformation in the area is primarily driven by movement of the Jurassic-aged Louann Salt, the basal stratigraphic unit within the basin (Pashin et al., 2014).

Figure 8 shows a structural cross section view through the geologic model of the Longleaf CCS Hub. The Longleaf CCS Hub sits down dip and to the east of the Citronelle Dome, a prominent salt cored anticline that hosts oil accumulations in reservoirs below the Ferry Lake Anhydrite (Esposito et al., 2008). The cross section shows the subsurface structure in the project from the Selma Group (upper Confining Zone) to the base of the Mooringsport Formation.

The Paluxy Formation shown in **Figure 8** is informally separated into two intervals, the Upper Paluxy which contains several thick, amalgamated sandstone bodies, and the Lower Paluxy which contains predominantly shale, vertically isolated sandstones, and a regionally continuous basal sandstone unit overlying the Mooringsport Formation.

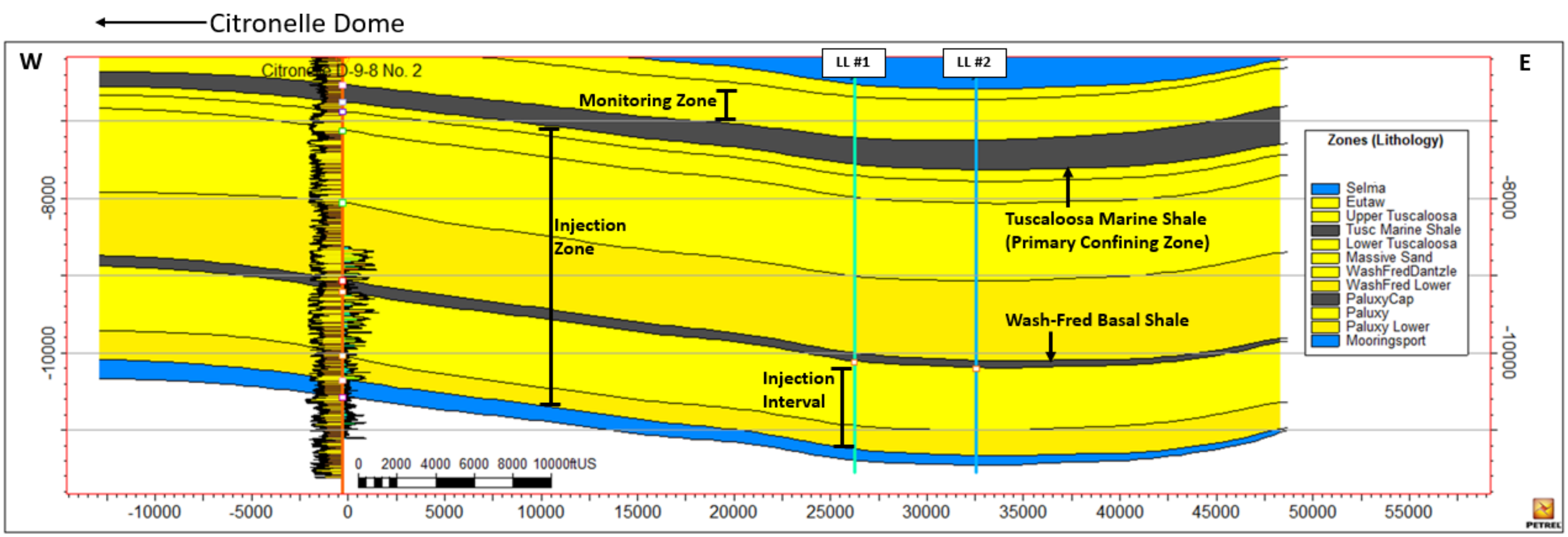


Figure 8. Cross sectional view through the 3D static earth model of the Longleaf CCS Hub from the Selma Group to the base of the Mooringsport.

The Wash-Fred Basal Shale, the secondary confining unit, is the lower black shale zone above the upper Paluxy injection interval. The upper Tuscaloosa Group, the above zone monitoring interval, is annotated above the Tuscaloosa Marine Shale (upper black shale zone). The log shown is the D-9-8 #2 with gamma ray plotted to the left and effective porosity (PHIE) plotted to the right.

B.3. Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

The evaluated 2D seismic lines indicate that there is one fault two miles east of the project AoR (Figure 2). This fault is known as the Hatters Pond Fault (HPF) and represents the western edge of the Mobile Graben. The fault is oriented north south and lies approximately five miles from the center of the proposed injection wells (**Figure 9**). Several deep oil and gas exploration wells drilled in northeastern Mobile County intersect the HPF, in the Cretaceous section, thus providing some insight into the Graben's structural geometry.

The Graben is about 3.5 miles wide in the upper part of the Cretaceous section and narrows considerably downward in section between the opposed normal faults, which dip approximately 65°. The faults on either side of the Graben have maximum displacement in the Jurassic section, and displacement dies out in the upper part of the Tertiary section. Fault displacement in the area to the east of the Longleaf CCS Hub area appears to be 3,000 ft to 3,500 ft in the Cretaceous section with offset decreasing up section (Pashin et al., 2008). This degree of displacement in the Cretaceous suggests that sandstones of the upper Paluxy may be juxtaposed with porous and permeable Upper Cretaceous units, such as Upper Tuscaloosa or the Eutaw Formations, inside the Graben. Thus, there may be lateral continuity in terms of porosity and permeability across the HPF. This is the assumption made in the baseline computational model where the east boundary of the model area, which effectively parallels the fault plane, is an open flow boundary.

If the fault acts as a lateral seal either due to juxtaposition of the injection zone against low permeability units or the fault plane itself has sealing properties (e.g., resulting from clay smearing or cataclasis), the fault plane would act as a pressure boundary (Meckel, 2007). The case where the eastern boundary of the model is hydraulically closed is one of the sensitivity cases presented and discussed in more detail in Section C.1 of the **Post-Injection Site Care and Site Closure Plan.**

To evaluate the potential for vertical leakage along the HPF, we used two approaches. First, we looked at analog hydrocarbon traps which use the fault plane as a structural trap. Located to the east of the Project is the Movico Field. Now abandoned, the Movico Field is a faulted anticline butted up against the HPF producing from the Jurassic Smackover formation at approximately -17,000 ft below sea level. The field's trap is created by the fault and juxtaposition with salt to the east of the HPF (Galicki, 1986). The larger Hatter's Pond Field to the south of the storage field has a similar trapping mechanism (Benson et al., 1981). The fact that these oilfields were butted up against the HPF provides evidence that it did not allow for vertical migration of buoyant hydrocarbon out of the Smackover.

There are no hydrocarbon pools along the HPF in the Cretaceous section above the Ferry Lake Anhydrite, likely due to the evaporite's impedance of vertical hydrocarbon migration. This is the case in the Citronelle oilfield, a giant salt-cored anticline with four-way closure to the west of the Longleaf CCS Hub (Esposito et al., 2008.). To determine the vertical sealing potential of the HPF above the confining zone, we used petroleum industry approaches developed for quantitative prediction of fault sealing potential (Meckel, T.A., 2007). One of these approaches, described by Yielding et al (1997) defines and uses a "shale gouge ratio", or SGR, to predict if faults may be sealing. In geologic units dominated by clay or shale beds, clay- and shale-rich smears can be formed on the fault plane, impeding vertical flow of buoyant fluids. SGR is defined as the cumulative thickness of shale in a unit divided by fault throw. The higher the SGR, the greater the potential for fault sealing. For example, using a global database of clastic reservoirs at less than 3 kilometers depth, Yielding et al. (2010) showed that faults with SGR below 20% have reduced sealing capacity and essentially leak over geologic time. Those with an SGR greater than 20% are likely sealing.

As mentioned, the HPF offset decreases up section. The existing 2D seismic lines that transect the HPF indicate an offset of approximately 760 ft at the top of the Selma Group. Directly overlying the Selma Group is the Porters Creek Clay unit of the Midway Group, which is a 500 ft thick, nearly 100% clay rich interval (**Figure 7**). The Porters Creek Clay is an oilfield seal in the Gilbertown Oil Field in Choctaw County, Alabama, approximately 60 miles to the north of the Longleaf CCS Hub (GSA Bulletin 168). Using the calculation described above, an SGR of 66% is calculated for the Porters Creek Clay interval (500 ft shale thickness divided by a fault throw of 760 ft). Thus, the HPF is likely a seal across this interval.

B.4. Injection Interval — Paluxy Formation

The Paluxy Formation contains a series of braided fluvial sandstones, conglomerates, and interfluvial mudstones that are present across the Gulf of Mexico Basin (Folaranmi, 2015) (**Figure 10).** The top of the Paluxy occurs at 10,080 ft subsea within the Longleaf CCS Hub (**Figure 11**). It is 1,140 ft thick with 473 ft of net sandstone thickness into two main subunits: the Upper Paluxy, consisting primarily of thick sandstones with thin shale interbeds, and the Lower Paluxy that contains predominantly shale with two thick sandstone sections (**Figure 12**).

Assessing the Paluxy Formation and its surrounding strata in well logs was done first in the D-9-8 #2 well where gamma ray, resistivity and porosity logs were available. The Ferry Lake Anhydrite serves as a marker horizon for picking the base of the Paluxy in well logs. The Ferry Lake has an especially low gamma ray and high resistivity response (**Figure 13**). The lower Paluxy sandstone is the first low gamma ray and resistivity signature above the Ferry Lake Anhydrite. The top of the Paluxy was picked based on the transition from a series of low gamma ray and resistivity signatures representing the thick sandstone bodies to a 144-foot-thick high gamma ray and resistivity signature interpreted as the Wash-Fred Basal Shale.

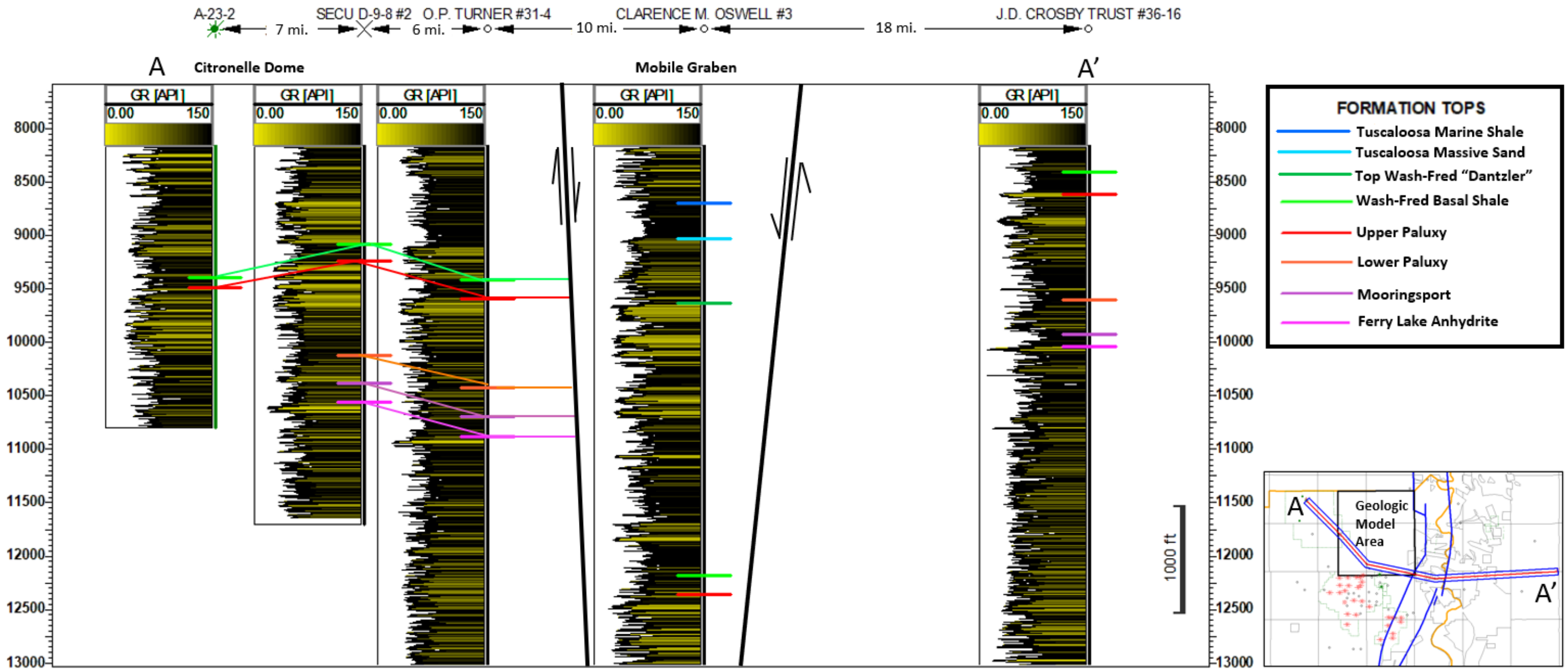


Figure 9. Regional structural cross section of the Wash-Fred Basal Shale, Paluxy injection interval, and Mooringsport/Ferry Lake interval through northeastern Mobile County and northwestern Baldwin County showing two prominent geologic structures in the region, the Citronelle Dome and the Mobile Graben.

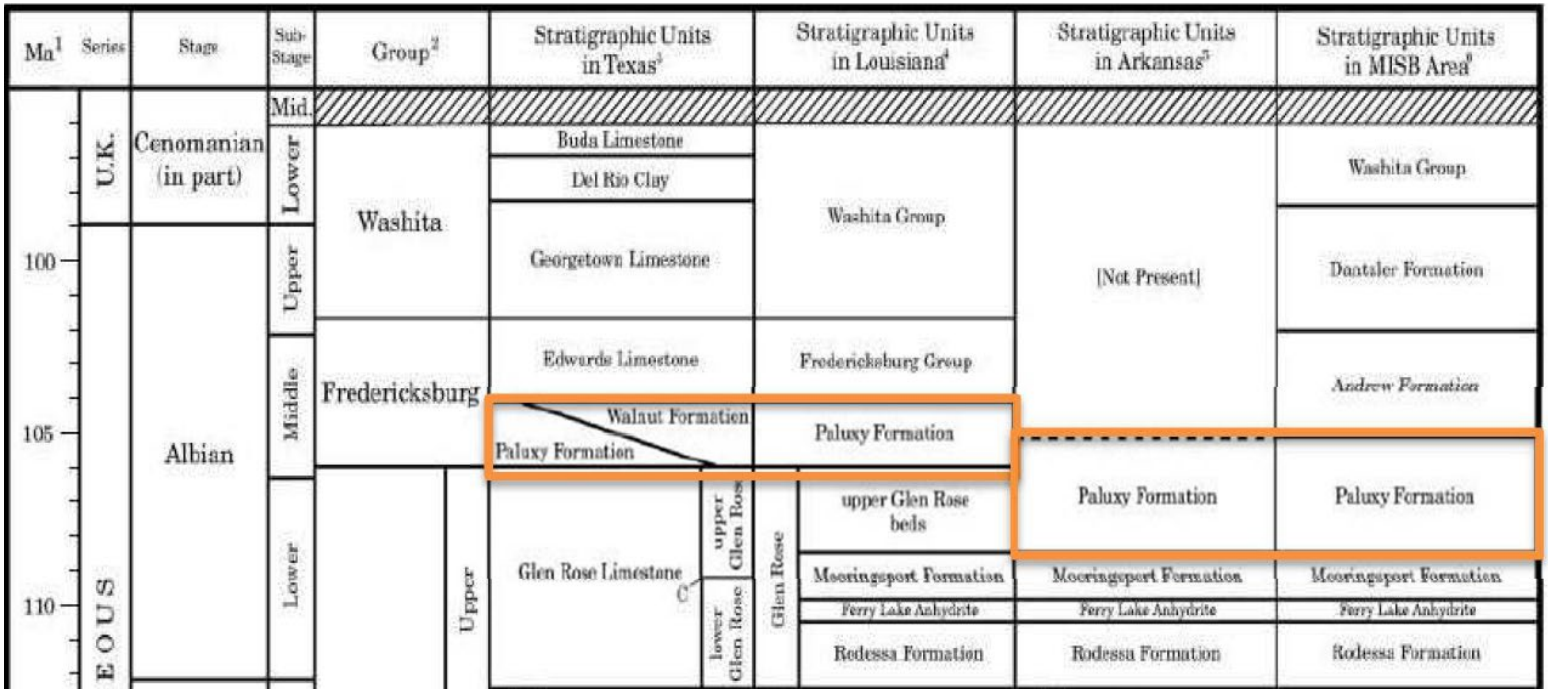


Figure 10. Stratigraphic columns across the continental Gulf of Mexico Basin indicating lateral continuity of the Paluxy Formation.

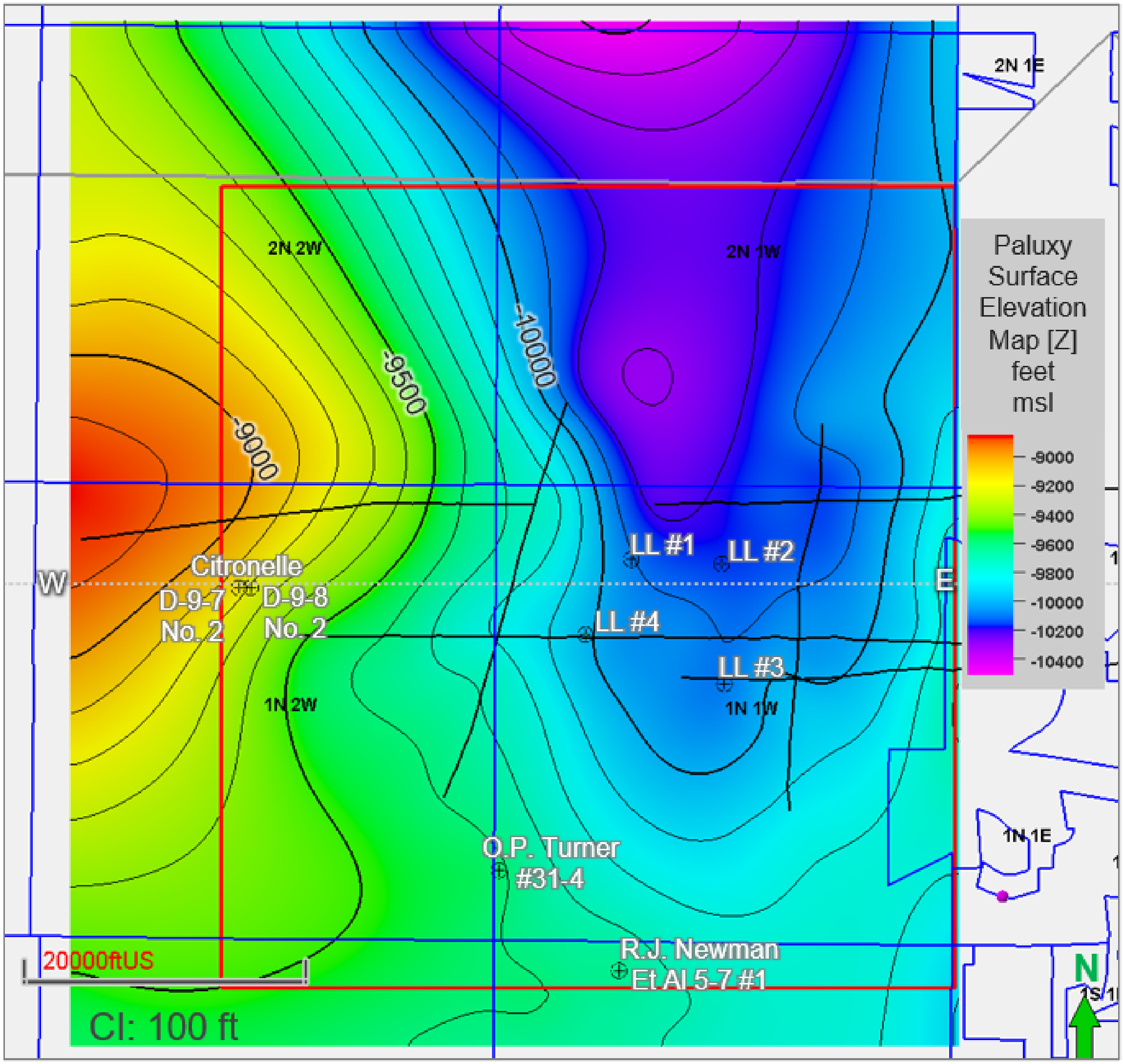


Figure 11. Structure contour map on the top of the Paluxy Formation in northeastern Mobile County. Datum is elevation in feet subsea. Contour interval: 100 ft. Black lines indicate surface track of 2D seismic lines.

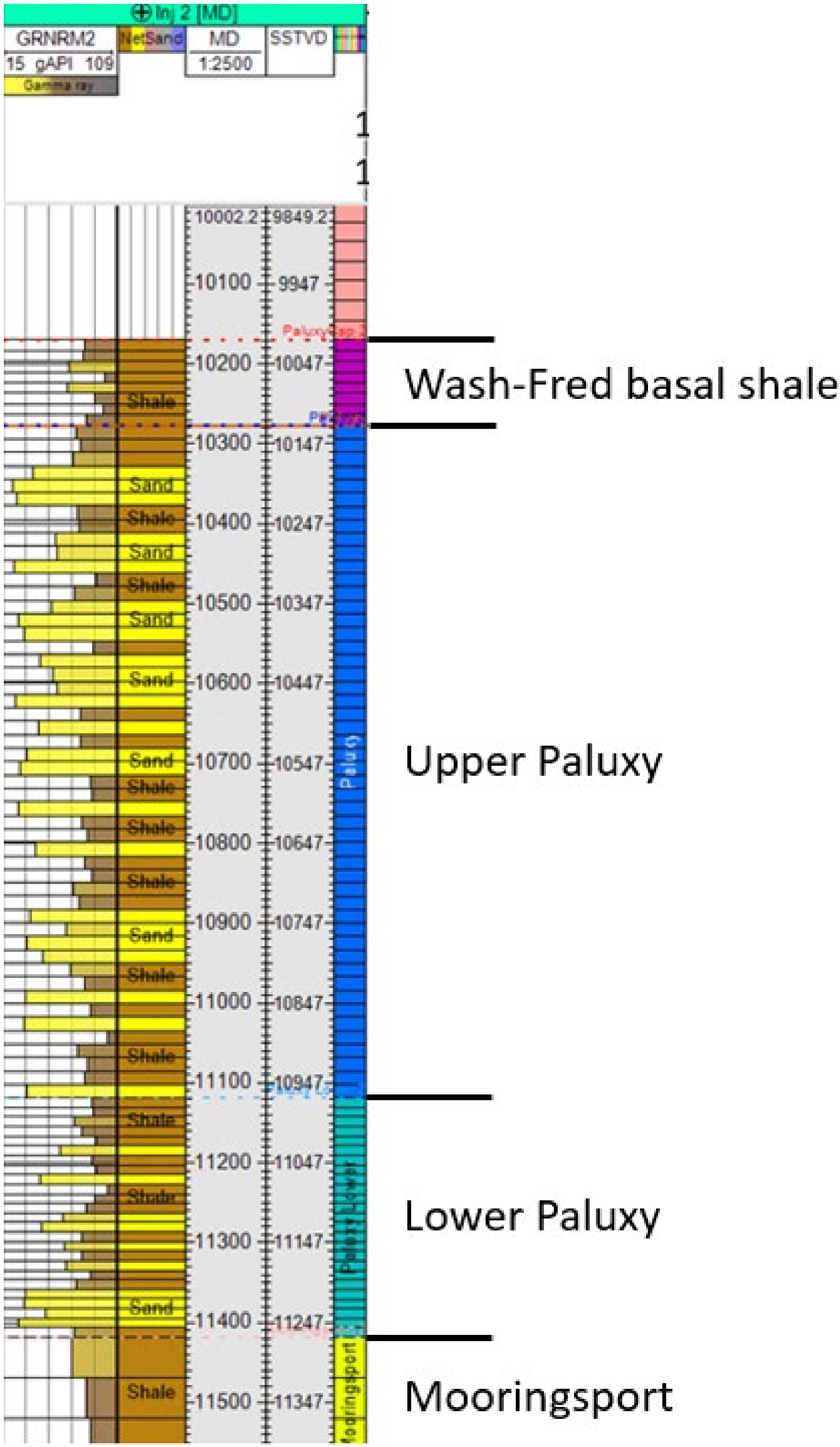


Figure 12. Net sand log derived from the 3D Static Earth Model at planned Injection well LL#1 with 473 ft. of net sand in the Paluxy Formation.

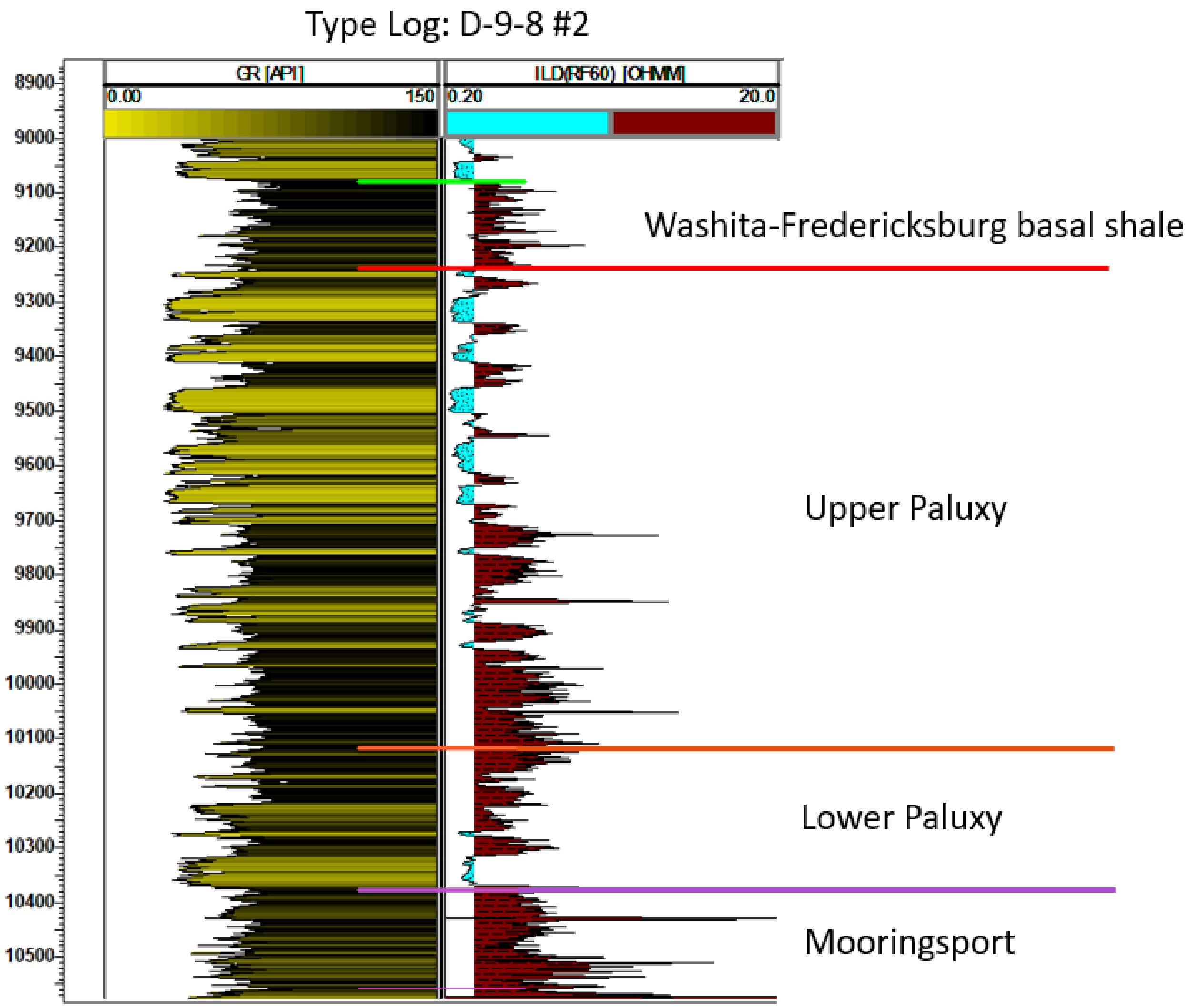


Figure 13. Gamma ray and resistivity logs from the Paluxy Formation type log, the D-9-8 #2 well, used to pick formation tops.

A deep resistivity cutoff of 2 ohms, that coincides with a decrease in gamma ray, indicates the approximate sand/shale cutoff. Blue shading on the resistivity log indicates net sand.

The Paluxy Formation is comprised of three lithofacies: the conglomerate lithofacies (**Figure 14**), the sandstone lithofacies (**Figure 15**), and the mudstone lithofacies (**Figure 16**) (Folaranmi, 2015). The sandstone lithofacies are the target for CO_2 injection in the Paluxy.

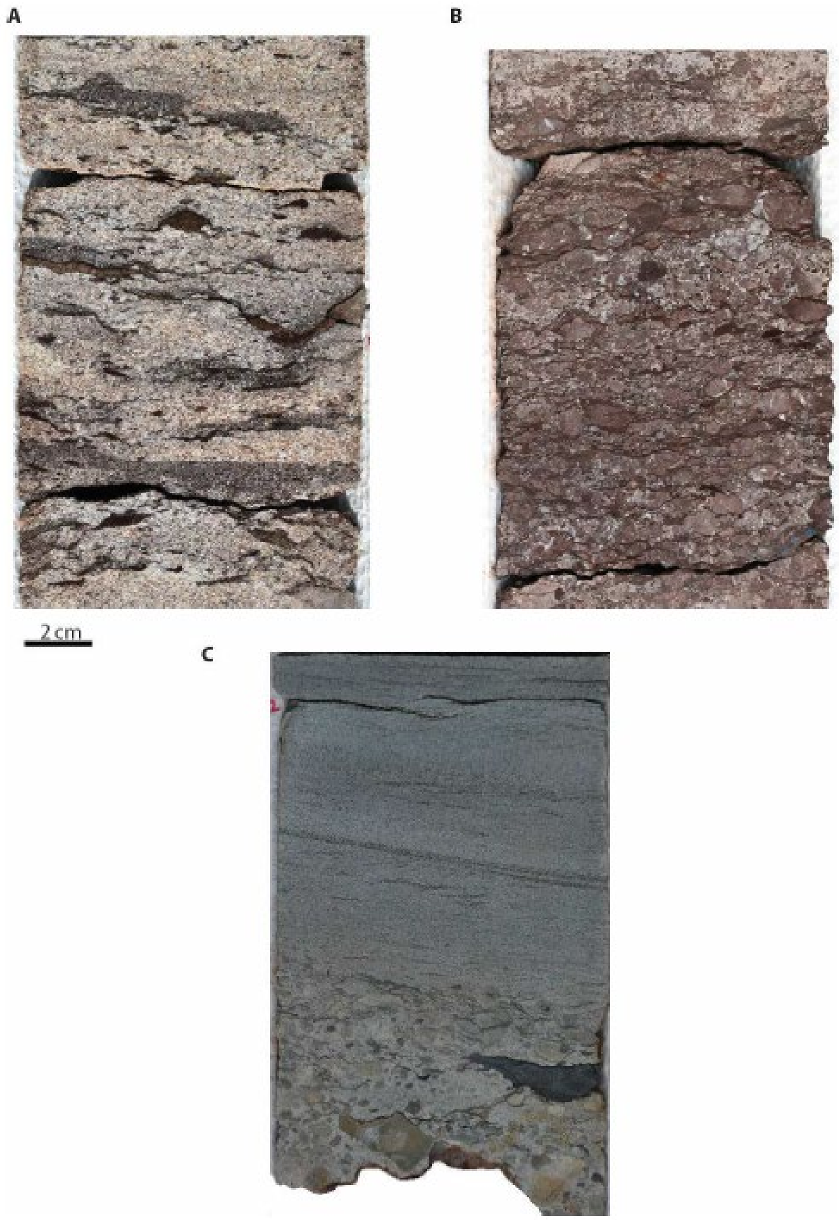


Figure 14. Core photos of the Paluxy conglomerate facies.

A: Well D-9-7 #2 at 9,624.5 ft. showing conglomeratic sandstone with platy shale intraclasts in a sandstone matrix. B: Well D-9-9 #2 at 9,419 ft. showing a clast-supported conglomerate containing clay-coated caliche clasts. C: Well D-9-9 #2 at 9,422 ft. showing argillaceous and dolomitic mudstone clasts overlain by siltstone.

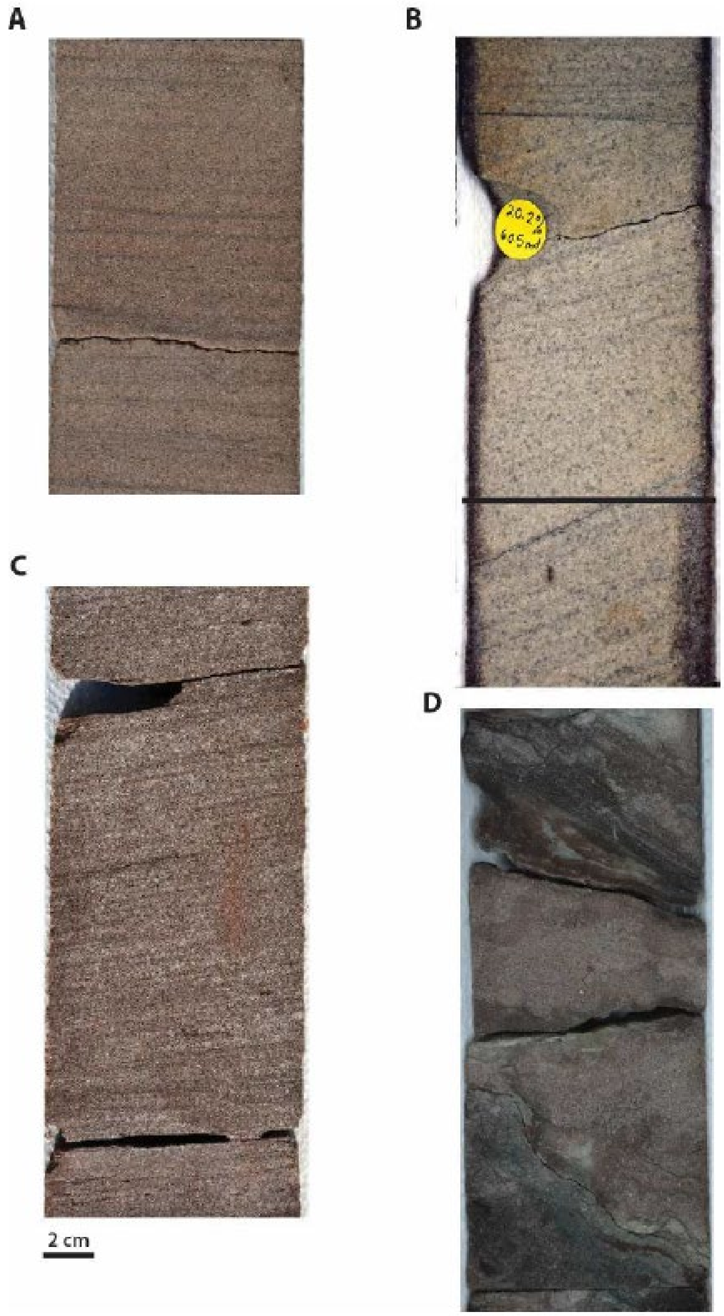


Figure 15. Core photos of the Paluxy sandstone facies.

A: Well D-9-7 #2 at 9,614 ft. showing horizontally laminated sandstone with thin micaceous laminae. B: Well D-9-8 #2 at 9,449 ft. showing planar cross-bedded sandstone. C: Well D-9-7 #2 at 9,582 ft. showing tangential cross bedding. D: Well D-9-8 #2 at 9,436 ft. showing fine-grained sandstone with convoluted beds.

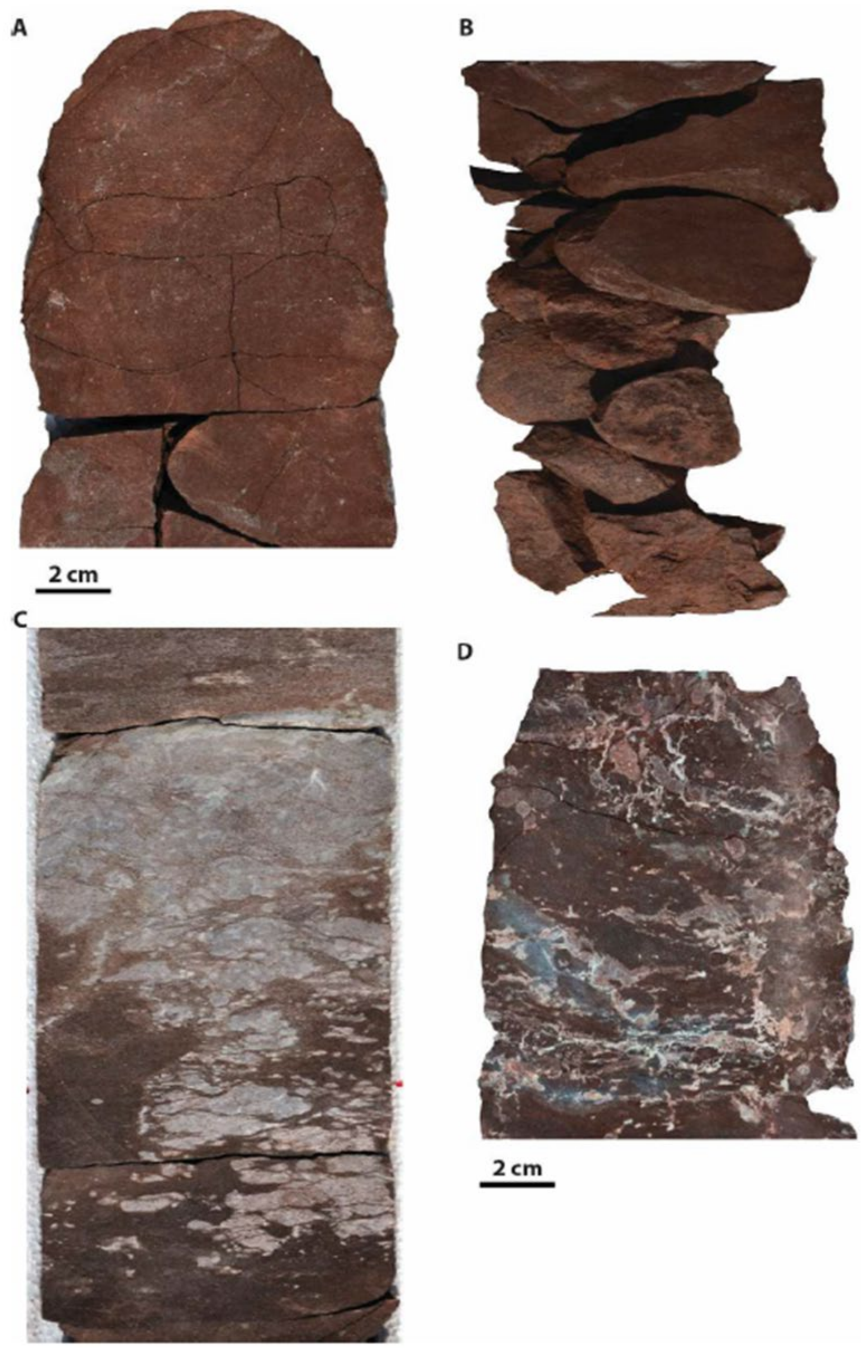


Figure 16. Core photos of the Paluxy mudstone facies.

A: Well D-9-7 #2 at 9,634 ft. showing blocky mudstone with horizontal and vertical cracks. B: Well D-9-7 #2 at 9,635 ft. showing mudstone with pedogenic slickensides and blocky peds. C: Well D-9-7 #2 at 9,590.5 ft. showing mottled mudstone with abundant calcareous nodules. D: Well D-9-9 #2 at 9,424.5 ft. showing Mudstone with calcite-filled cracks and small caliche nodules.

Mineralogy

The Paluxy sandstone is composed of quartz, feldspar, and lithic fragments, and is classified as a subarkosic, feldspathic litharenite according to the Folk (1980) classification system (**Figure 17**) (Pashin et al., 2020). Quartz grains are mostly monocrystalline, occasionally polycrystalline, and sub-angular to sub-rounded and slightly elongate to spherical (**Figure 18**). Quartz content ranges from 65-95% with roughly equal proportions of feldspar and lithic fragments. Orthoclase and plagioclase feldspar are both present and are commonly partially dissolved or vacuolized resulting in secondary porosity. Traces of accessory minerals include biotite and muscovite micas, and trace amounts of zircon grains, calcite cement, and kaolinite exist within pore spaces (**Figure 19**). XRD analysis indicated that clay minerals within the Paluxy are predominantly illite and kaolinite (Folaranmi, 2015). This composition is low in reactive minerals, such as calcite, and therefore is compatible with CO_2 injection.

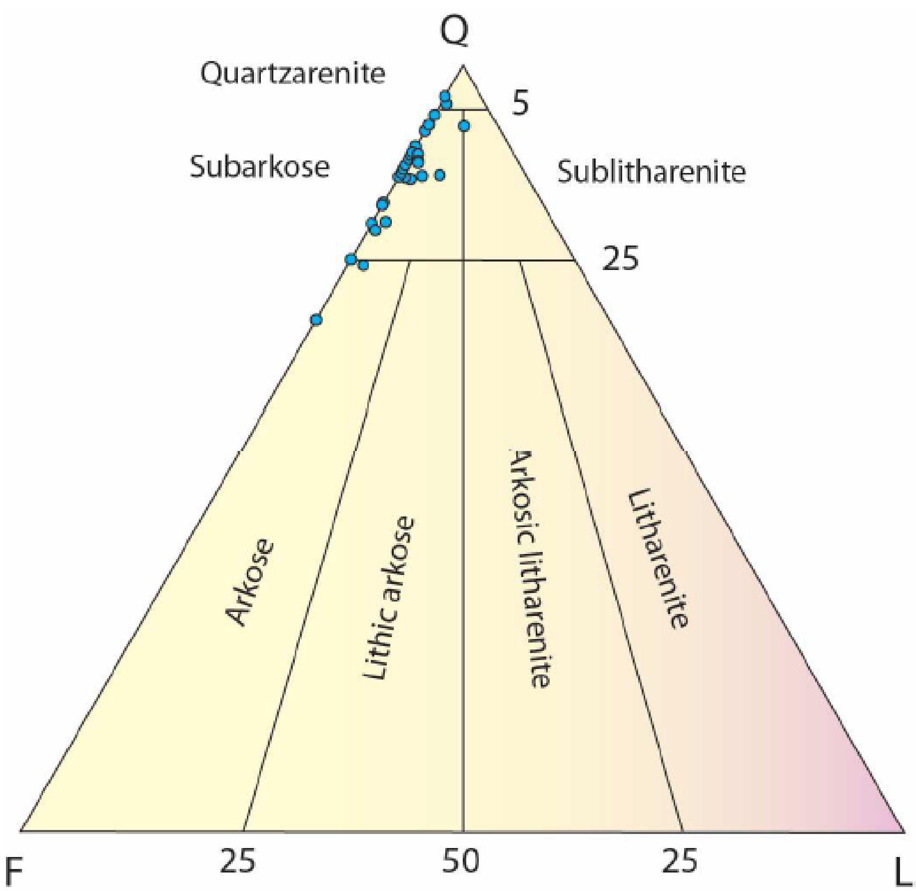


Figure 17. QFL diagram for sandstones in the Paluxy Formation (modified from Folk, 1980). The core data from the Paluxy sandstones plot predominantly as subarkosic sandstones.

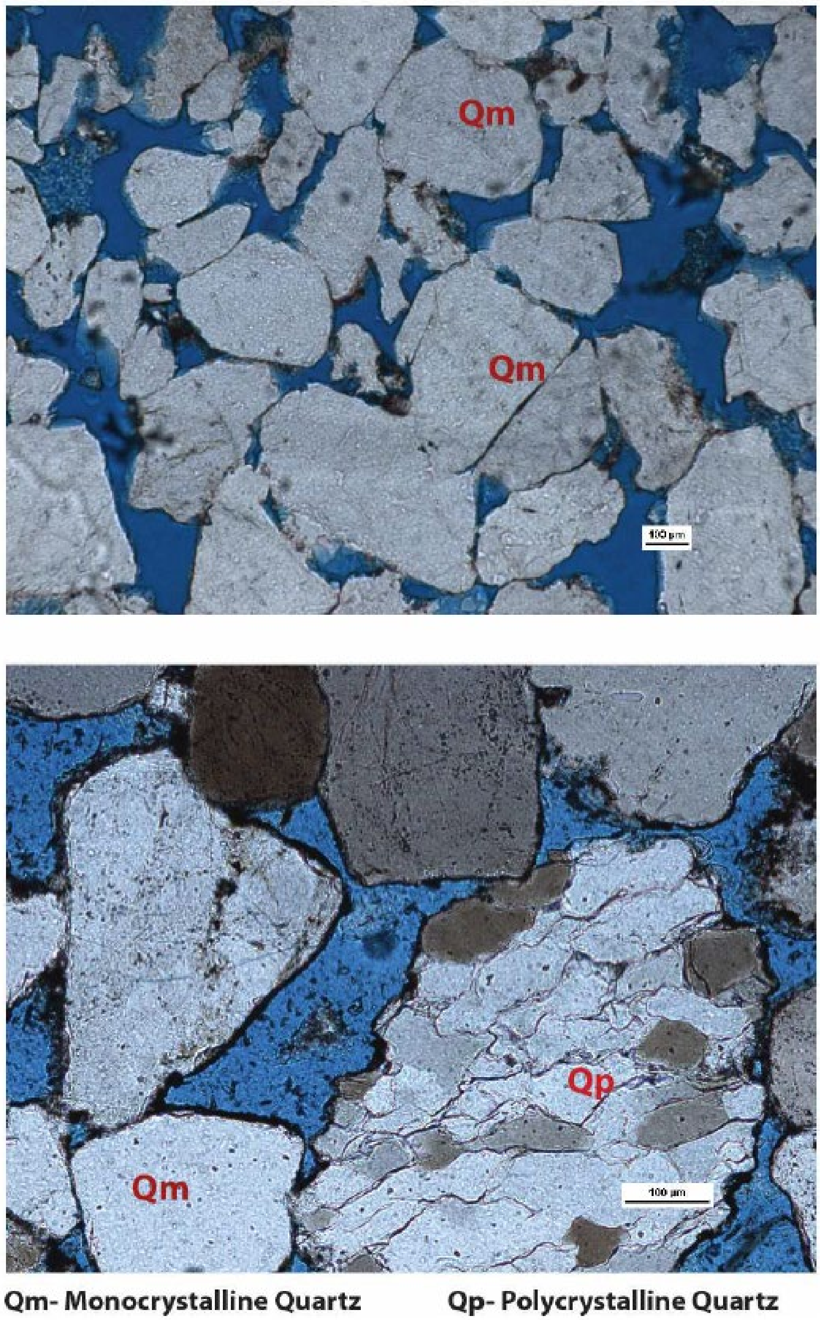


Figure 18. Thin section photomicrograph of Paluxy sandstone subangular and subrounded grains showing the dominance of monocrystalline quartz and an example of a polycrystalline grain.

Dark coating on grains is clay coating. From well D-9-7 #2, top photo at 9,604.35 ft; bottom photo at 9,600 ft.

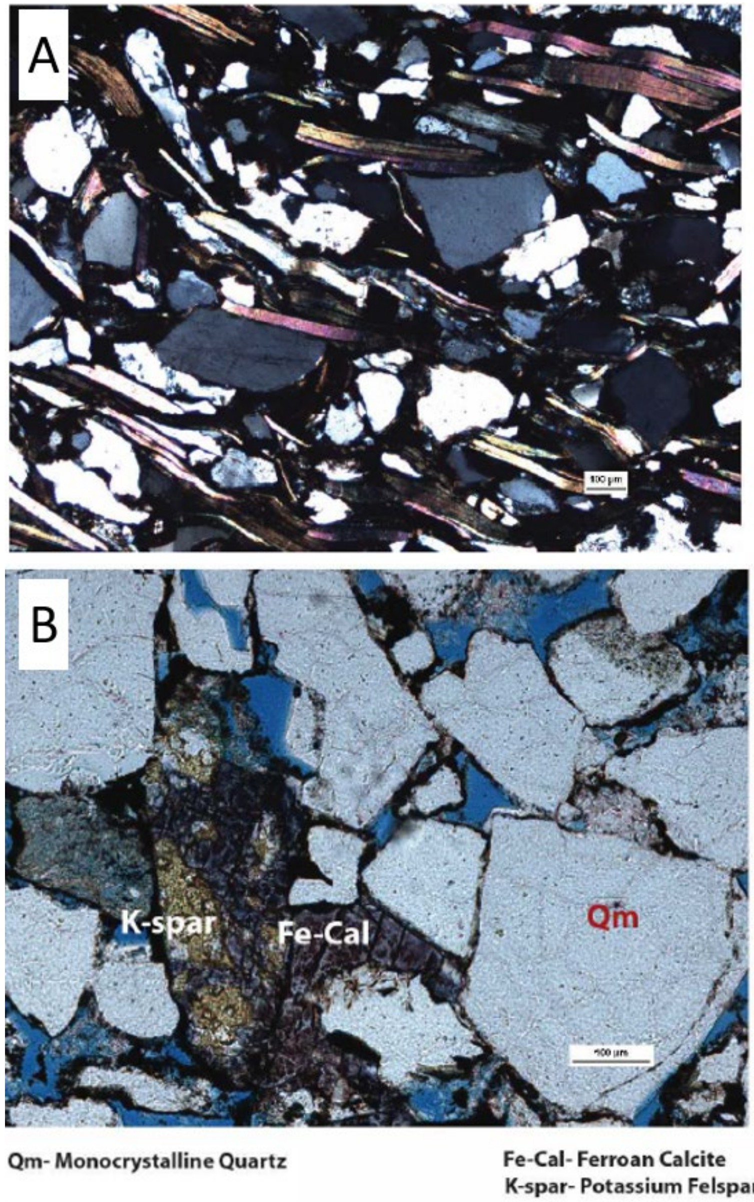


Figure 19. Thin section photomicrograph of Paluxy sandstone grains.

A: from well D-9-8 #2 at 10,455 ft. showing cross-polarized light sample with birefringent biotite grains mixed with equant quartz and feldspar grains. B: from well D-9-7 #2 at 9,575.5 ft. showing clay coating on grains (dark brown), partially vacuolized potassium feldspar, and ferroan calcite cement replacing a vacuolized potassium feldspar grain.

Porosity and Permeability

Routine Core Analysis (RCA) was conducted on whole core obtained from the D-9-8 #2 well from a depth of 9,400 ft to 9,461 ft, a thick Upper Paluxy sandstone interval. **Figure 20** provides core photos and descriptions of a portion of the core collected that is representative of the Upper Paluxy sandstones, from 9,430 ft to 9,460 ft.

RCA was conducted on 10-foot intervals from 9,400 ft to 9,461 ft to calculate an average porosity and permeability for each interval. Sandstone porosity ranged from 8% to 19%, and permeability ranged from 26 millidarcies (mD) to 437 mD. A porosity-permeability relationship was calculated by fitting an exponential trendline to a cross plot of porosity and permeability values from the geologic model (**Figure 21**).

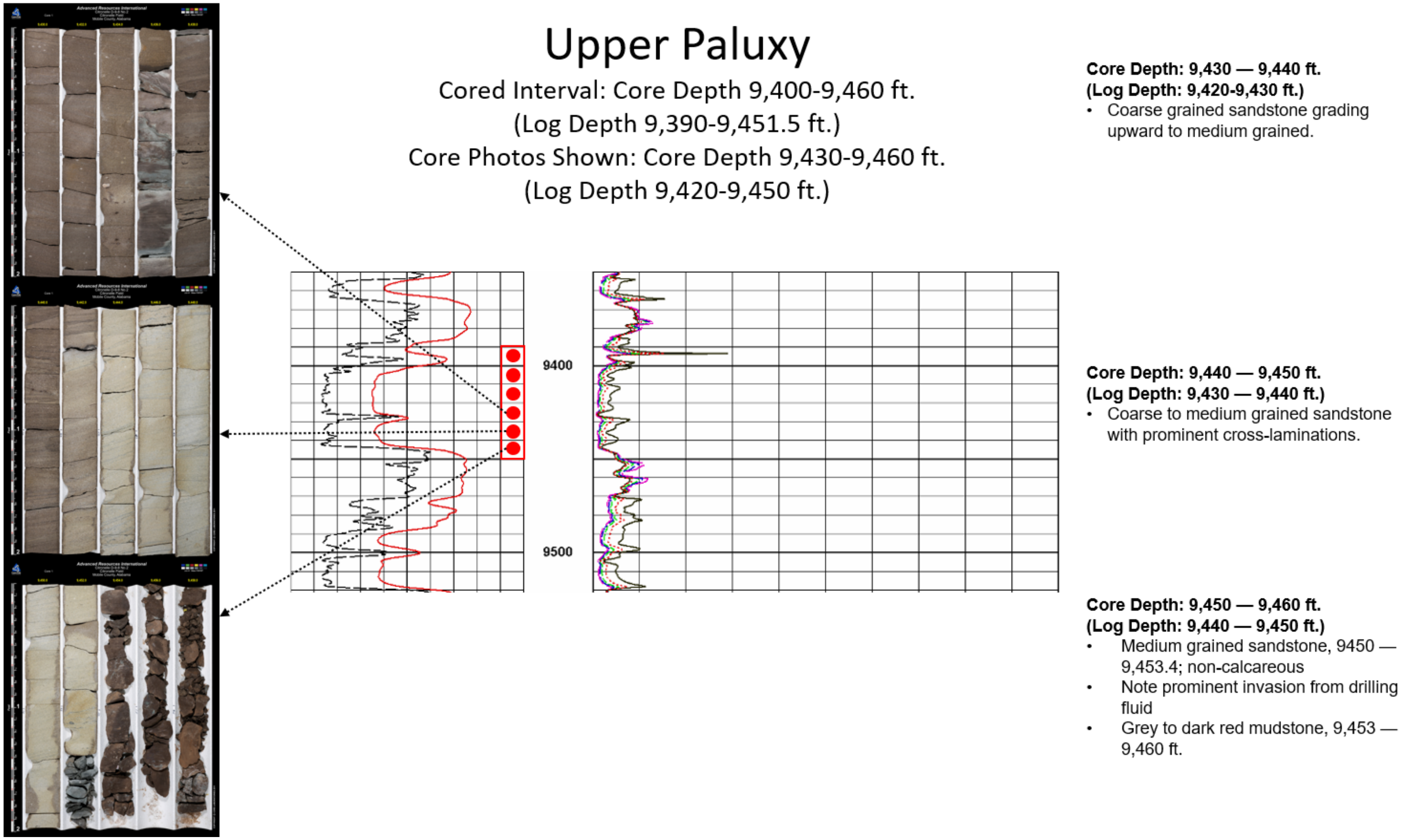


Figure 20. Whole core photos from the upper Paluxy Formation (9,400 ft. to 9,460 ft.) correlated to log signatures. Each photo contains 10 ft. of core. Lithologic descriptions of the core are to the right of the log.

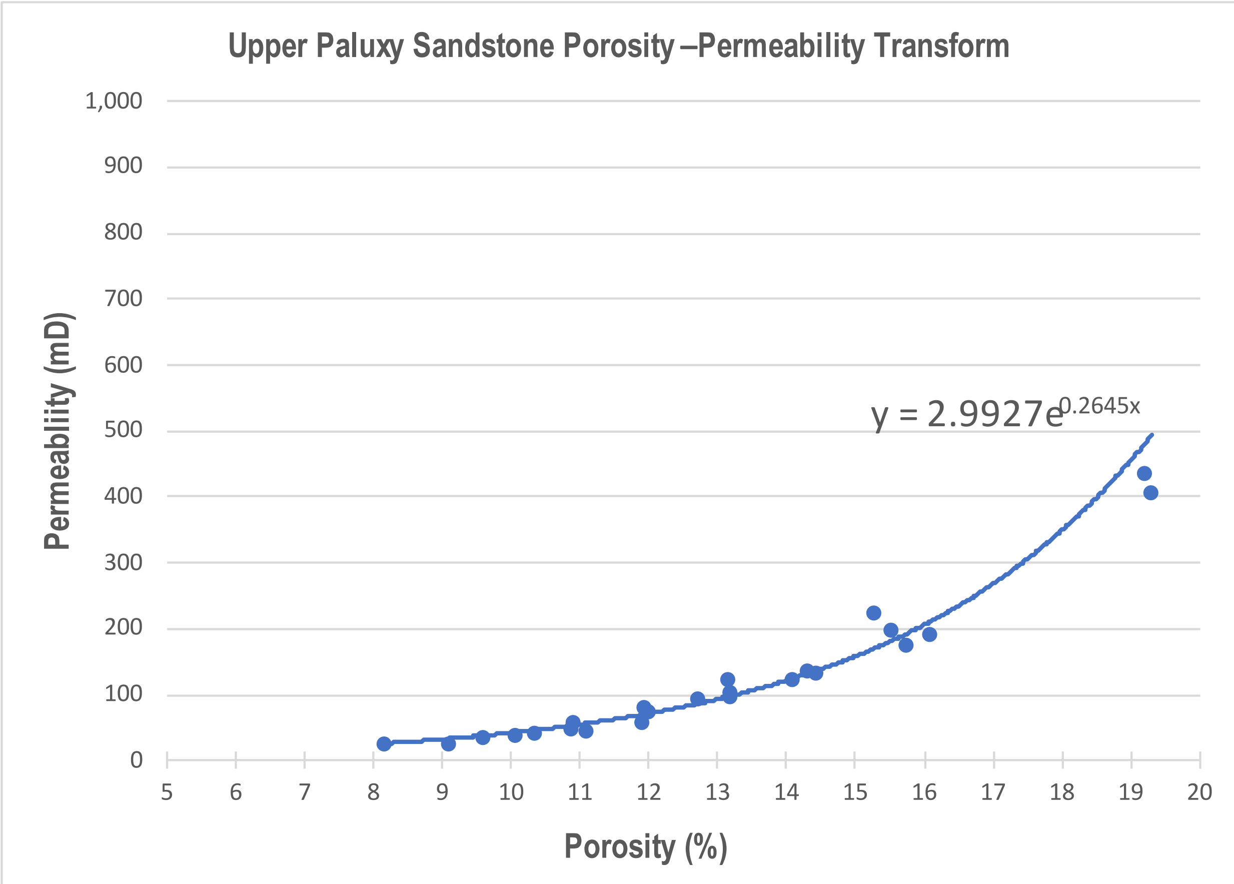


Figure 21. Porosity-permeability cross plot based on modeled upper Paluxy porosity and permeability values from the geologic model.

The whole core acquired from the Lower Paluxy sandstone interval was recovered from a depth of 10,430 ft to 10,465 ft. Core photos from the Lower Paluxy sandstones from 10,440 ft to 10,465 ft. (core depth) are shown in **Figure 22** (Note: Core depths 10,460 ft to 10,465 ft contain discontinuous core segments). Average sandstone porosity ranged from 8% to 16%, and average sandstone permeability ranged from 24 mD to 115 mD, with the higher permeability in the coarser grained sandstones at the base of the Lower Paluxy. A porosity-permeability relationship was calculated by fitting an exponential trendline to a cross plot of porosity and permeability values from the geologic model (**Figure 23**).

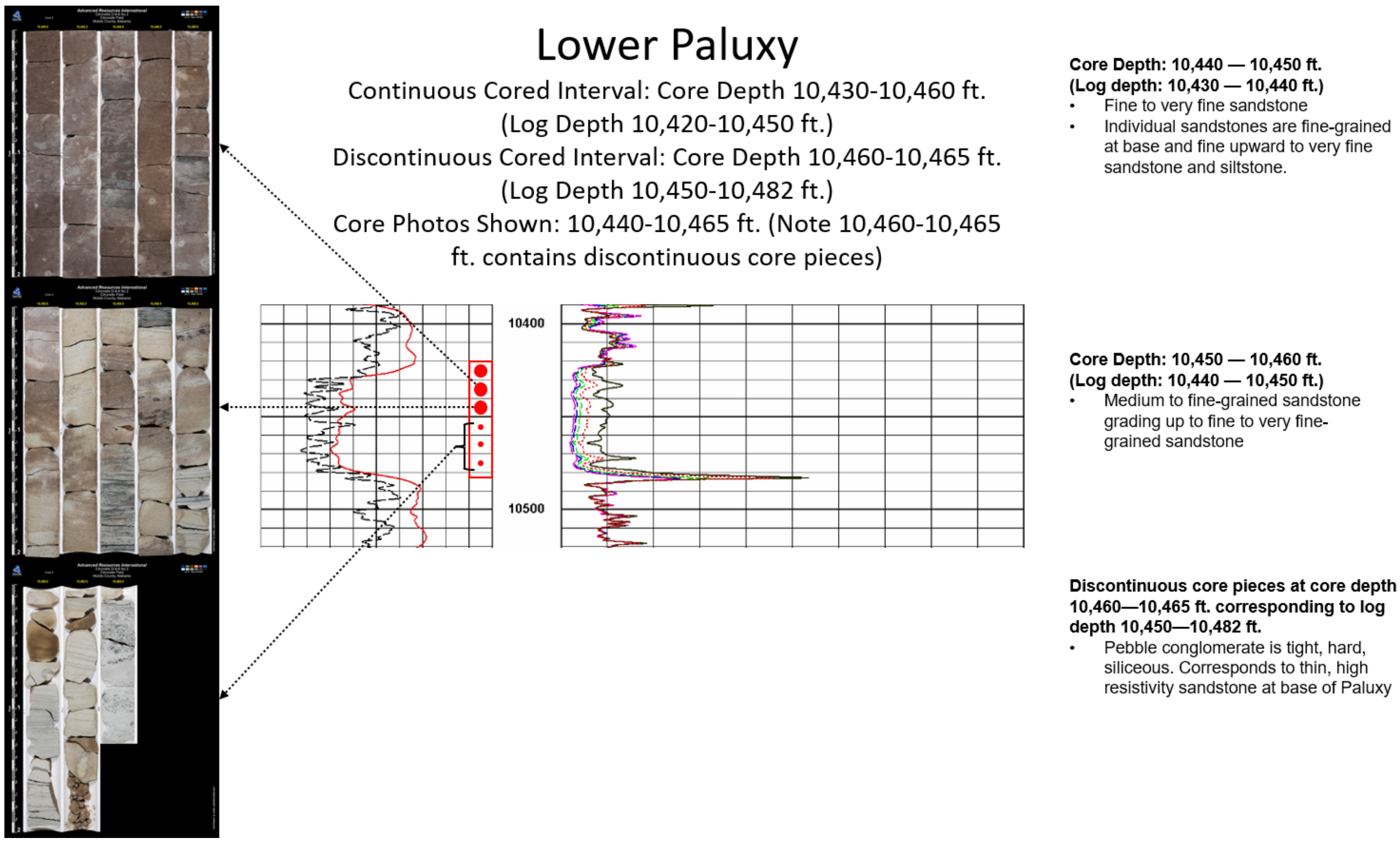


Figure 22. Whole core photos from the lower Paluxy Formation (10,430 ft. to 10,482 ft.) correlated to log signatures. Each photo contains 10 ft. of core. Lithologic descriptions of the core are to the right of the log.

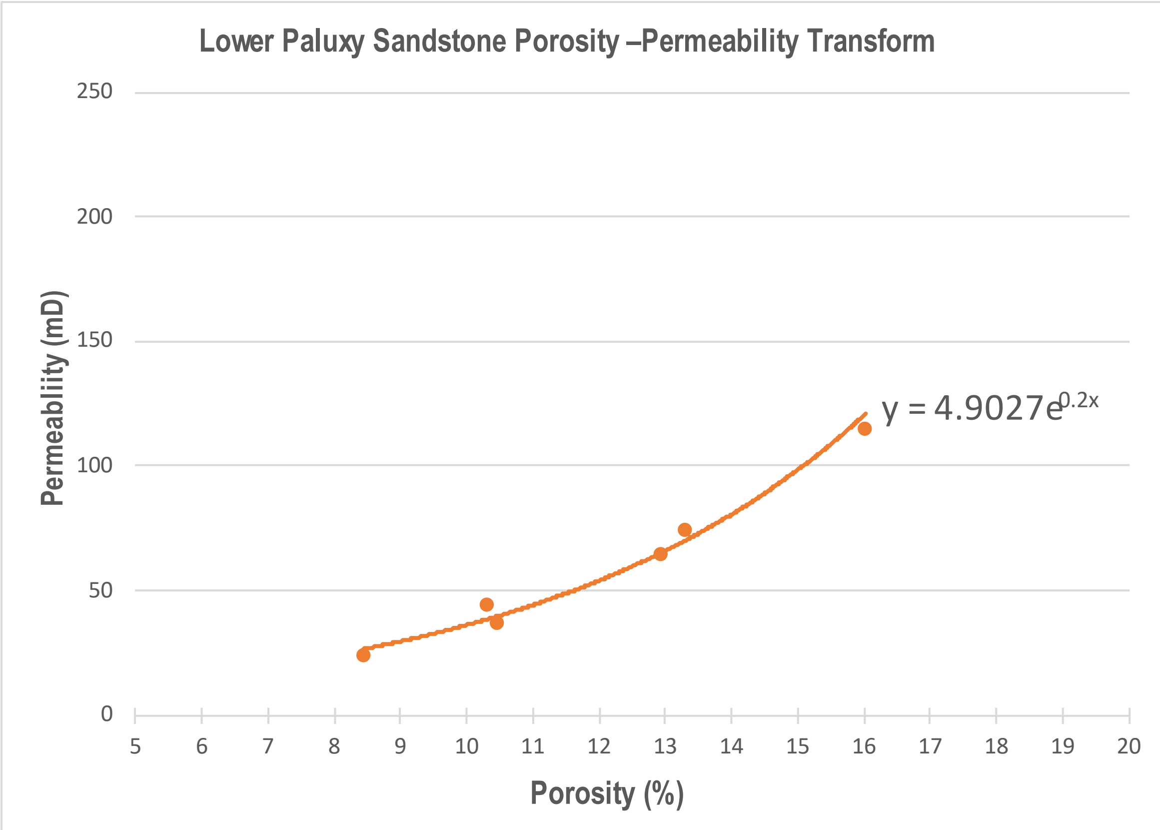


Figure 23. Porosity-permeability cross plot based on modeled lower Paluxy porosity and permeability values from the geologic model.

<u>Reservoir Pressure</u>

The reservoir pore pressure gradient was calculated using data from downhole monitoring equipment in the D-9-8 #2 well. The baseline pore pressure in the Paluxy was recorded in the shallowest upper Paluxy sandstone interval with a top gauge at 9,416 ft. and a bottom gauge at 9,441 ft. The baseline pressure at the top gauge was 4,369 psi, and at the bottom gauge was 4,385 psi, which provided a calculated pressure gradient of 0.463 psi/ft (**Figure 24**).

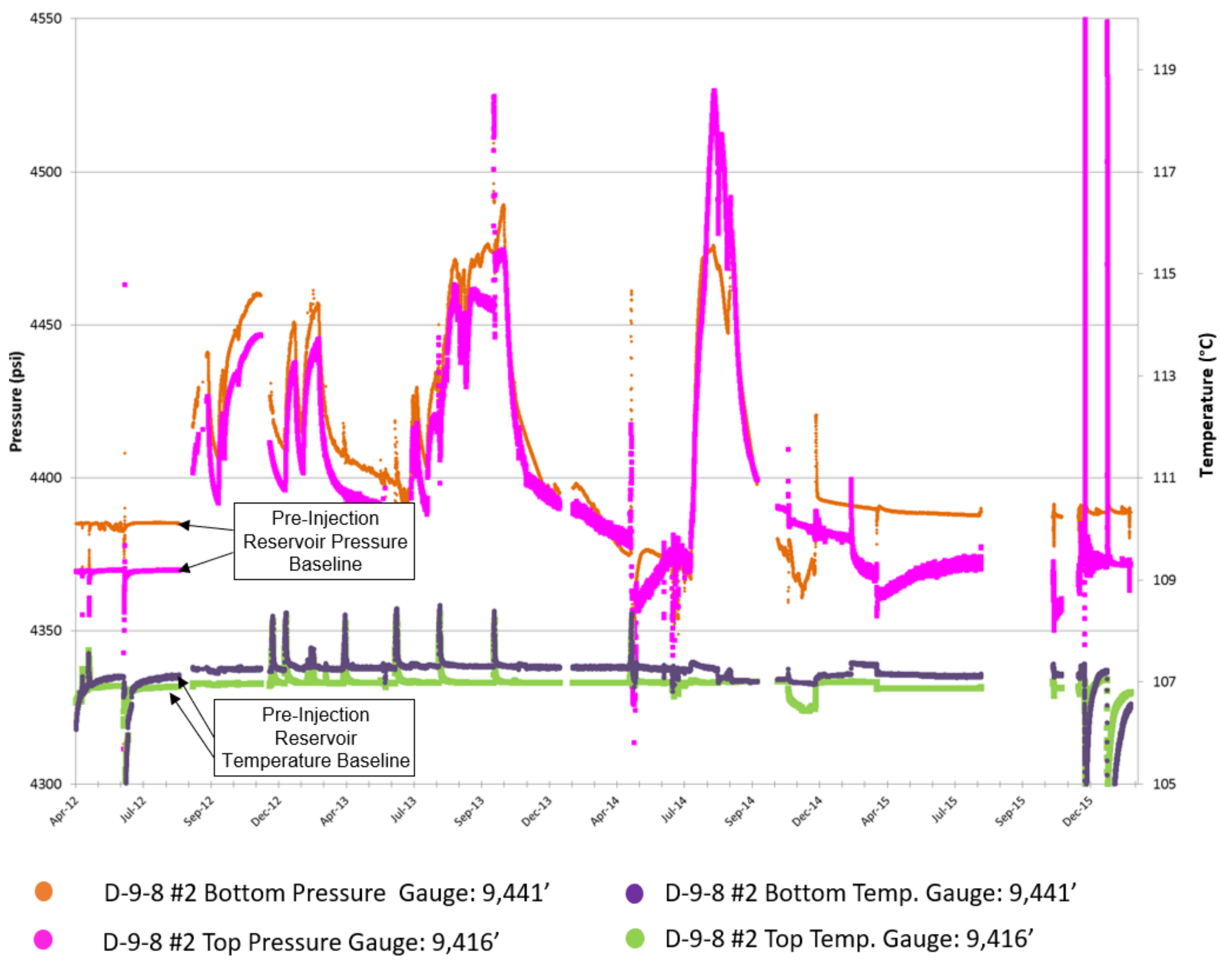


Figure 24. Pressure and temperature gauge data from the D-9-8 #2 Paluxy in-zone monitoring well. Pre-injection baseline data used to calculate pressure and temperature gradients for the Paluxy is annotated.

Reservoir Temperature

Temperature data was also recorded from gauges in the D-9-8 #2 well. The pre-injection baseline reservoir temperature for the Paluxy at the top gauge was 106.9°C (224.4°F) and at the bottom gauge was 107.1°C (224.8°F) (**Figure 24**). Salt domes, such as the Citronelle Dome, may exert an effect on surficial heat flow and thereby higher than normal temperatures (Dees and Smith, 1982). The domes can function as a heat sink at their bases and as a heat source at their tops, causing high geothermal gradients in the overlying sedimentary rock units. This could be the case for the elevated temperatures sometimes encountered in south Alabama within the Mississippi Interior Salt Basin. Based on temperature gauge readings, an elevated temperature gradient of 1.65 °F/100 ft. is assumed in our geologic modeling of the Longleaf CCS Hub. Data gathered from the first monitoring well, which will serve as the characterization well for the Longleaf CCS Hub, will determine if an elevated temperature gradient exists to the east of the Dome where CO_2 will be injected.

Capillary Pressure

Capillary pressure injection data for the Paluxy Formation will be acquired as part of the ***Pre-Operational Testing Plan*** provided with this application under a separate cover.

Static Storage Resource Potential

Based on these petrophysical and reservoir characteristics, the P10, P50, and P90 Static Storage Potential for the Paluxy Formation was calculated at 2.3, 4.3, and 7.4 Mt per square mile, respectively (Goodman et al., 2011). A summary of the calculations for the Upper Paluxy, Lower Paluxy, and Total Paluxy is provided in **Table 4**.

Table 4: Estimate of Static CO_2 Storage Resource Potential for the Paluxy Formation

Estimate of Static CO_2 Storage Resource Potential—Paluxy Formation				
Producing Interval		U. Paluxy Total	L. Paluxy Total	Total/Average
Net Thickness (ft)		395	78	473
Avg Porosity (%)		13%	11%	–
Avg Pressure (psi)		4,878	5,215	–
Reservoir Temperature (°F)		240	251	–
CO_2 Density (lb/ft^3)		40.5	40.7	–
Storage Potential ($Mt/mi.^2$)	P10 (7.4% Efficiency)	1.9	0.4	2.3
	P50 (14% Efficiency)	3.7	0.7	4.3
	P90 (24% Efficiency)	6.3	1.1	7.4

B.5. Confining Zones

B.5.1. Primary Confining Zone - Tuscaloosa Marine Shale

The Tuscaloosa Marine Shale occurs at a depth of approximately 7,250 ft subsea in the Longleaf CCS Hub (**Figure 25**) and is about 300 ft thick (**Figure 26**). This shale is persistent across the Gulf of Mexico Basin, serving as the principal reservoir seal for oil and gas accumulations in the Lower Tuscaloosa Group (Petrusak et al., 2009).

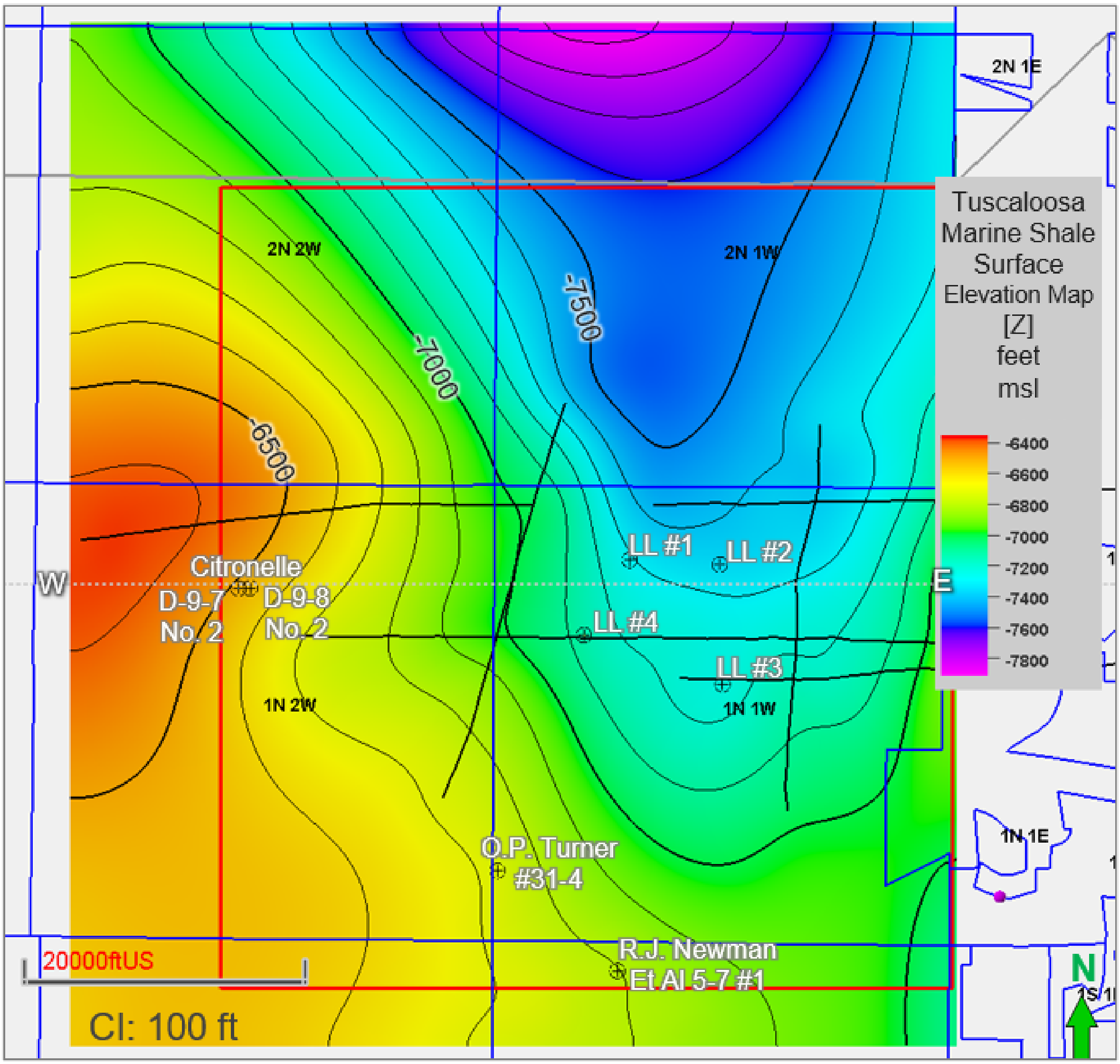


Figure 25. Structure contour map on the top of the Tuscaloosa Marine Shale in northeastern Mobile County. Datum is shown in feet subsea. Contour interval: 100 ft. Black lines indicate surface track of 2D seismic lines.

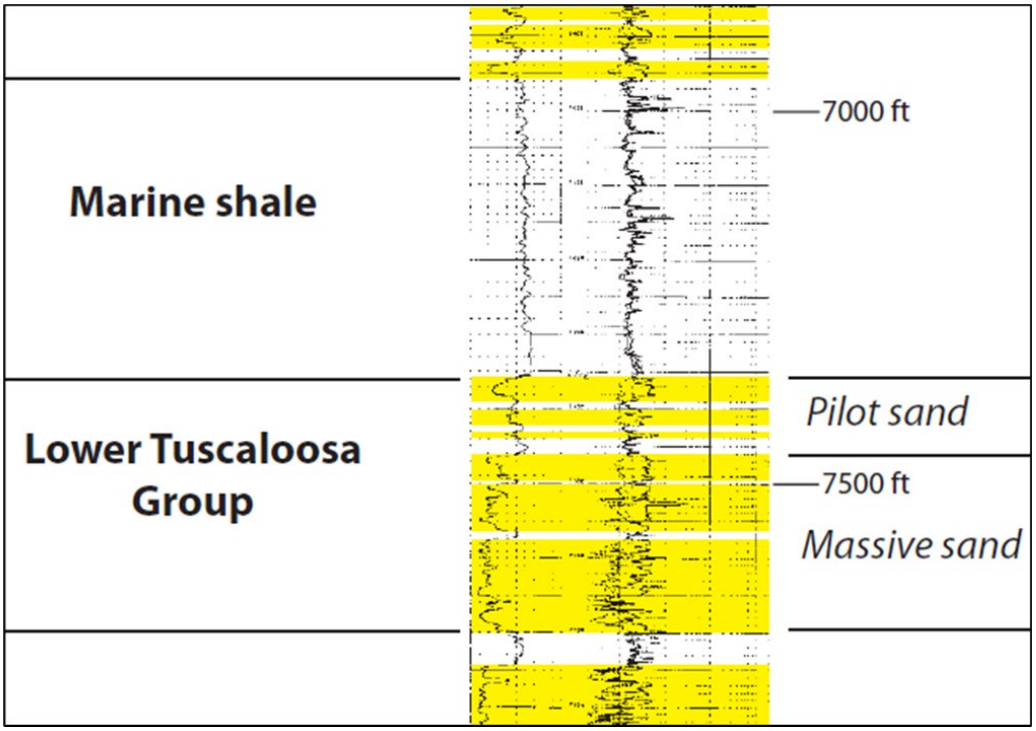


Figure 26. Type log for the Tuscaloosa Marine Shale in the Longleaf CCS Hub from well #B-31-5.

In southwest Alabama, the Tuscaloosa Marine Shale is predominantly gray to black mudstone grading into siltstone and very fine-grained sandstone at the top (Petrusak et al., 2009). **Figure 27** shows a whole core sample collected from a 30-foot section of the Tuscaloosa Marine Shale in Jackson County, Mississippi approximately 40 miles from the Longleaf CCS Hub.

Mercury capillary pressure tests were performed on select samples from the whole core under ambient (surface) and overburden pressure (subsurface) conditions. Results from samples under overburden pressure conditions show low effective porosity (1–2%) and low permeabilities at the microdarcy to nanodarcy scale, indicating favorable sealing characteristics (**Table 5**).

Table 5: Summary of Tuscaloosa Marine Shale core from the Mississippi Power Co. #11-1, Jackson County, MS.

Core Depth (ft.)	Effective Core Porosity (%)	Core permeability (mD)
7,914 - 7,916	2.0	1.27×10^{-5}
7,923 - 7,926	1.5	8.08×10^{-6}
7,928 - 7,931	1.2	2.07×10^{-5}

B.5.2. Secondary Confining Interval—Washita-Fredericksburg Basal Shale

The Wash-Fred Basal Shale, the secondary confining interval for the Paluxy Formation, occurs at 9,990 ft subsea within the Longleaf CCS Hub (**Figure 28**). The Basal Shale overlying the Paluxy Formation ranges from 96 to 172 ft. thick and is present throughout Longleaf CCS Hub (**Figure 29**).

Mud log descriptions from the D-9-8 #2 well indicate the Basal Shale of the Wash-Fred is a gray, brick red, and red-brown mottled shale with traces of silty- to very fine-grained sand and limestone streaks (**Figure 30**). Renken et al. (1989) and Pashin et al. (2008) suggested that the Basal Shale of the Wash-Fred contains interfluvial redbeds, and this interpretation is supported by the mud log descriptions from the D-9-8 #2 well.

An integrated mineralogical and petrophysical interpretation from the DOE/NETL SECARB Phase III demonstration at the SE Citronelle Unit indicates an effective porosity across the Wash-Fred Basal Shale of less than 5% (**Figure 31**). This petrophysical interpretation also estimated permeability of the Basal Shale using the Power Law function, indicating 145 ft of shale with permeability less than 1.0×10^{-5} mD (**Figure 32**).

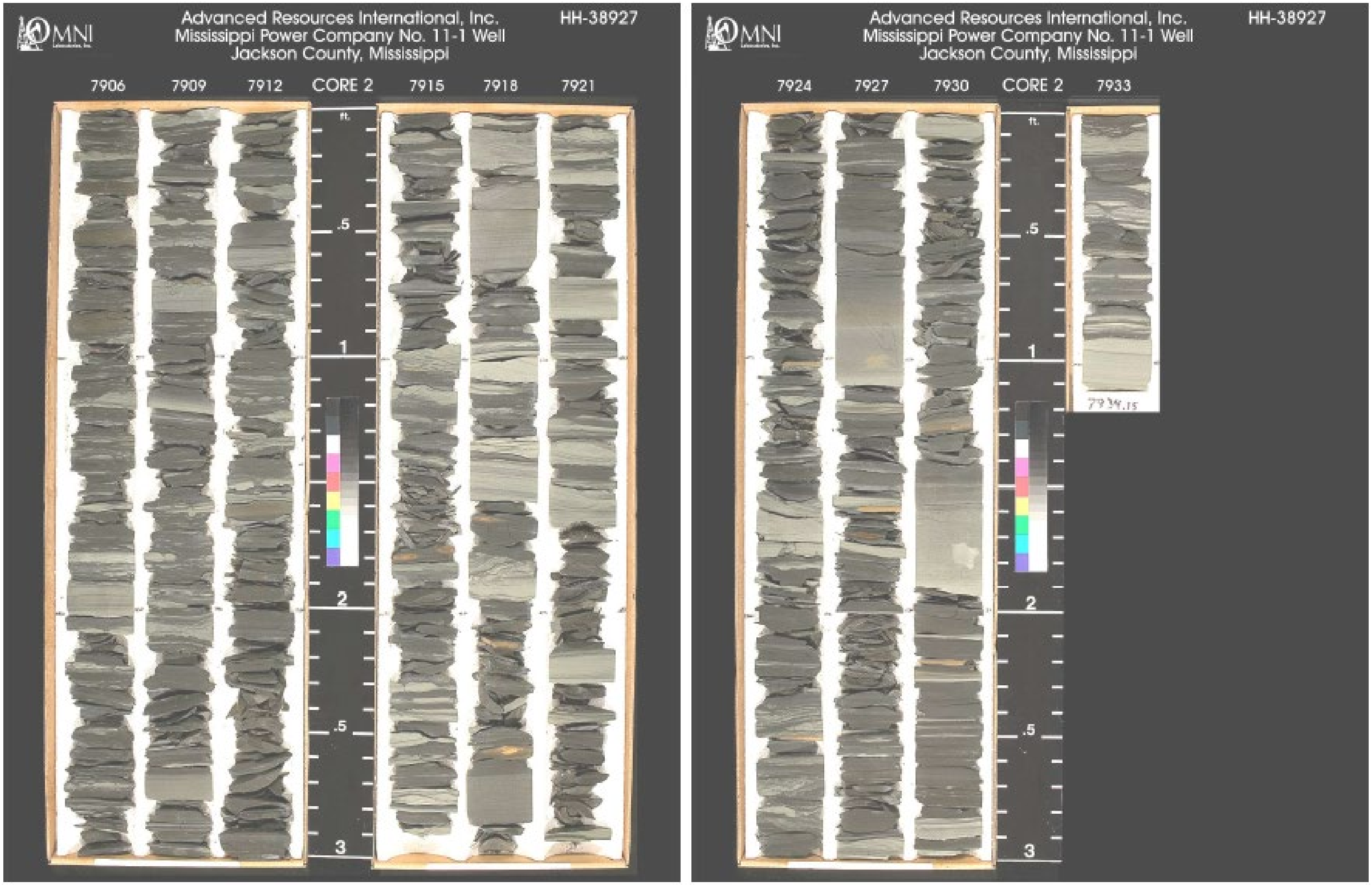


Figure 27. Tuscaloosa Marine Shale whole core photos from the Mississippi Power Co. #11-1 well (from Petrusak et al., 2009).

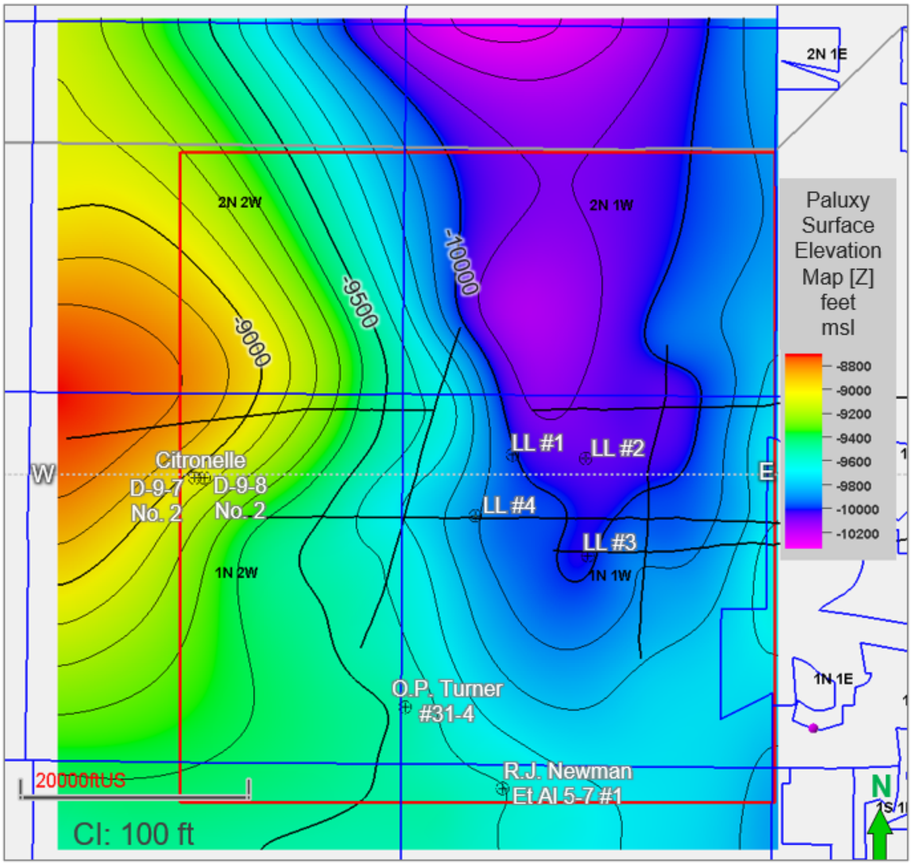


Figure 28. Structure contour map on the top of the Washita-Fredericksburg basal shale. Datum is elevation subsea (ft.). Contour interval: 100 ft.

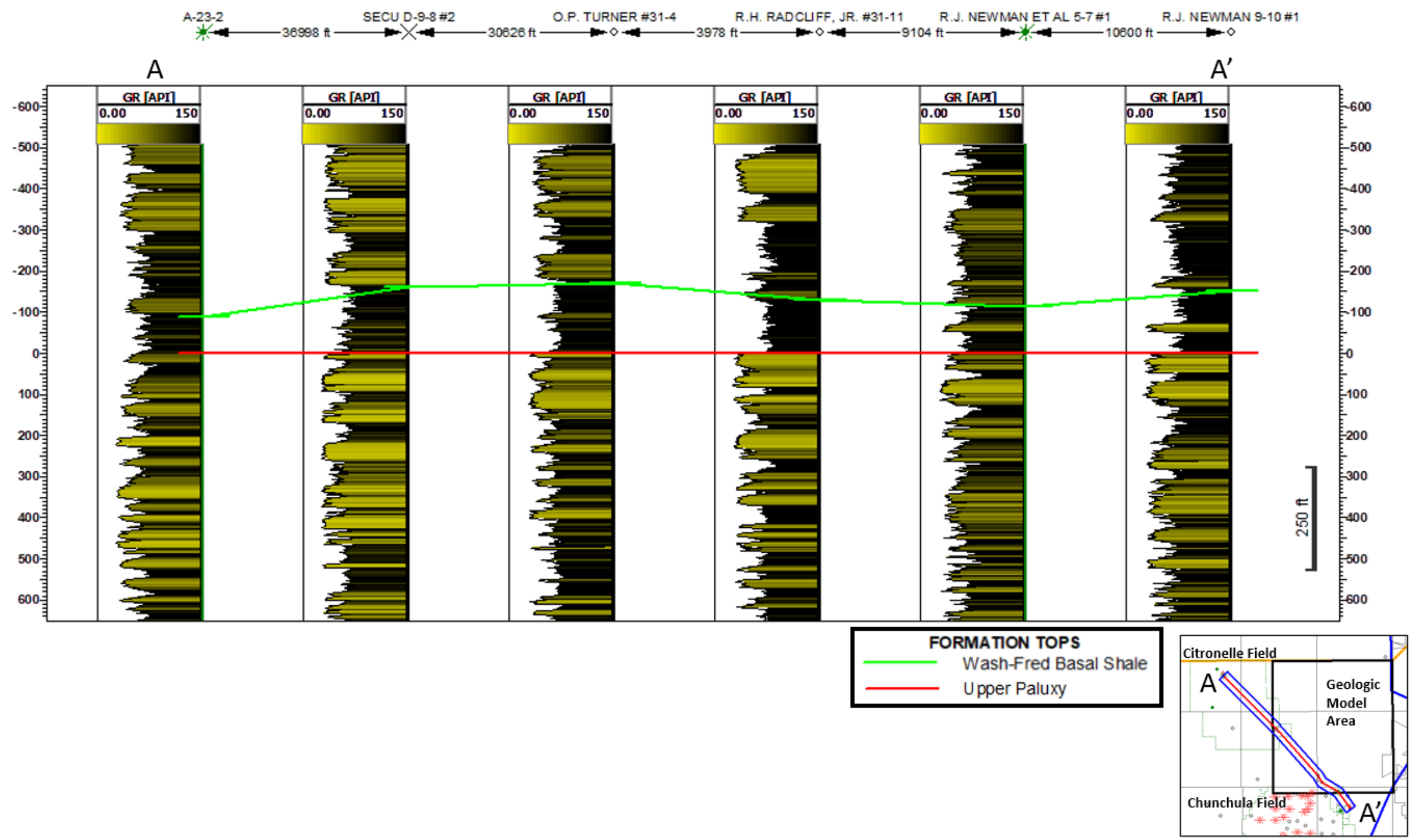


Figure 29. Stratigraphic cross section of the Washita-Fredericksburg basal shale through wells west and south of the Longleaf CCS Hub AoR.

Thickness ranges between 96 ft in the A-32-2 well on the northern edge of the Citronelle Dome and 172 ft in the O.P. Turner #31-4 well located at the southern edge of the geologic model area.

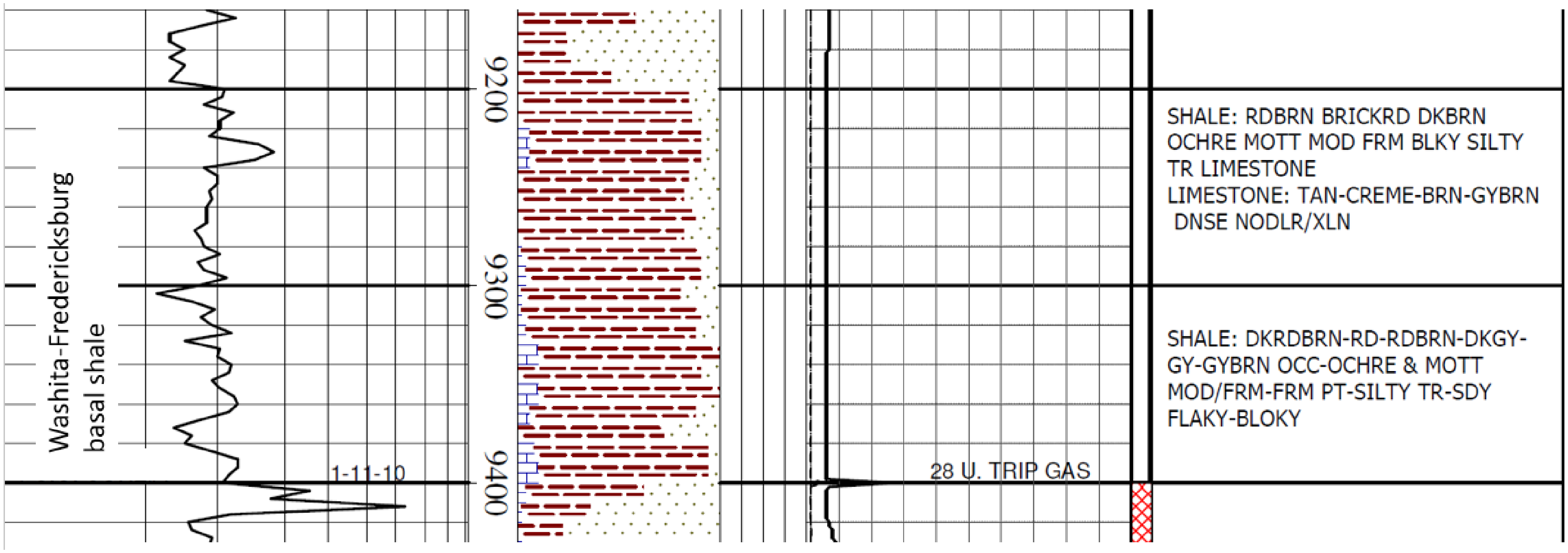


Figure 30. Mud log with lithology descriptions from the basal shale of the Washita Fredericksburg interval.

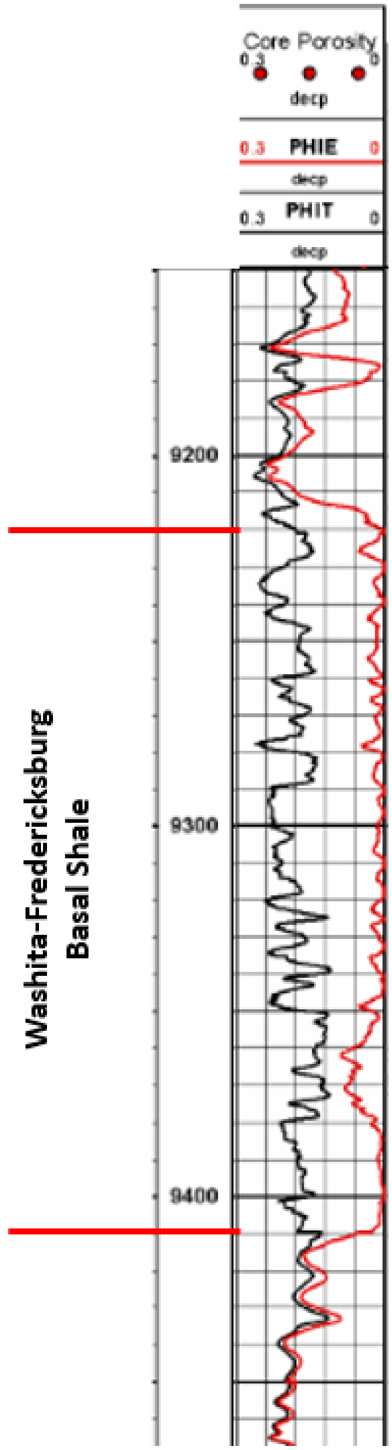
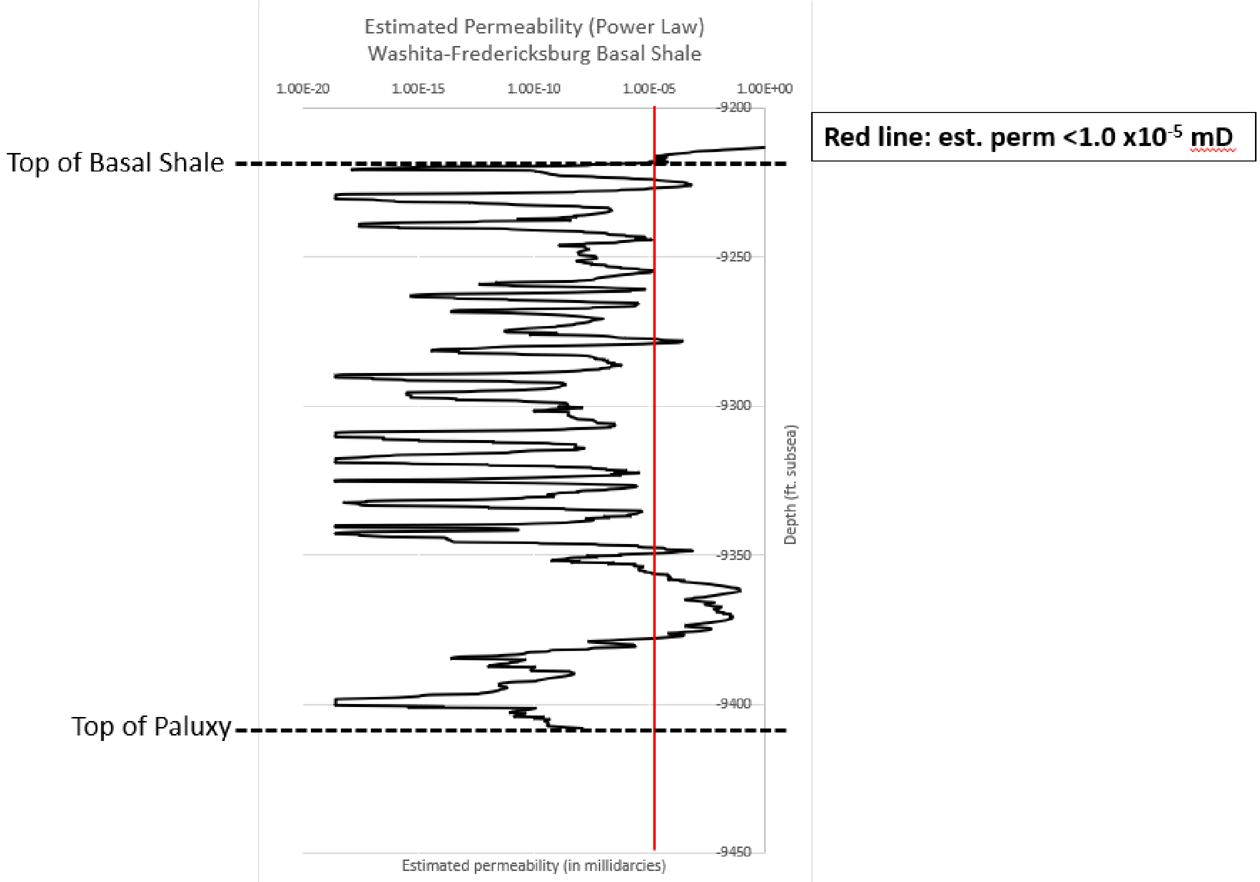


Figure 31. Porosity log from the D-9-7 #2 well over the Washita-Fredericksburg basal shale showing the total porosity (PHIT) in black and effective porosity (PHIE) in red.

Porosity logs were generated using the Halliburton GEM™ elemental analysis tool.



Permeability plotted on X-axis; depth (ft. subsea) plotted on Y-axis.

Figure 32. Logarithmic scale plot of the Power Law estimated permeability log from the D-9-7 #2 well across the Washita-Fredericksburg basal shale.

B.5.3. Additional Overlying Confining Intervals

Above the primary confining zone, the Tuscaloosa Marine Shale, there are additional confining strata that provide additional protection against CO_2 plume migration into USDWs. The combined Selma and Midway Groups form a 2,000 ft uppermost confining unit below the base of USDW. The depth and thickness of these formations are shown in **Table 6**.

Table 6: Summary of additional confining zones above the Washita-Fredericksburg basal shale.

Formation Name	Lithology	Formation Top Depth (ft. subsea)	Thickness (ft.)	Depth Below Base of USDW (ft.)
Selma Group	Chalk	5,500	1,500	3,800
Midway Group	Clay	5,000	500	3,300

B.5.3a. Selma Group

The Upper Cretaceous Selma Group, with a thickness of 1,500 ft, serves as the uppermost confining zone between the injection zone and the base of USDW. The Selma Group consists of low permeability chalk, marl, and limestone that is the primary seal for oil accumulations in the underlying Eutaw Formation in Alabama (Pashin et al., 2000; Pashin et al., 2008). The Selma is predominantly bioturbated and fossiliferous chalk with significant quantities of marl and grain-supported limestone (Pashin et al., 2008). The upper Selma is mainly chalk, while the lower Selma consists of transitionary strata between the chalk and underlying Eutaw Formation siliciclastic sediments. In the Longleaf CCS Hub, the top of the Selma Group occurs at approximately 4,500 ft subsea. **Figure 33** shows the structure of the Selma Group in Alabama and Mississippi, and **Figure 34** shows gross thickness of the Selma.

A whole core sample from the Selma Group was recovered from the Mississippi Power Co. #11-1 well in Jackson County, Mississippi, the same well from which the Tuscaloosa Marine Shale core was acquired.

Core photos from the Selma show the unit contains very fine-grained, burrowed to bioturbated, fossiliferous limestone and chalk (**Figure 35**). Dissolution along laminations with siltstones and clays contains concentrated silt and mud grains in coalescing dissolution seams. Ambient pressure condition tests were conducted on the Selma core samples, which showed porosity ranging from 12.5 to 16.7% and core plug permeability ranging from 0.012 mD to 0.108 mD; the porosity and permeability of the Selma chalks under overburden pressure conditions are expected to be several orders of magnitude lower.

B.5.3b. Midway Group

Directly overlying the Selma Group is the Midway Group, consisting of about 500 ft. of dark brown to black marine clay that is regionally extensive across the Mississippi Interior Salt Basin (Mancini et al., 1999).

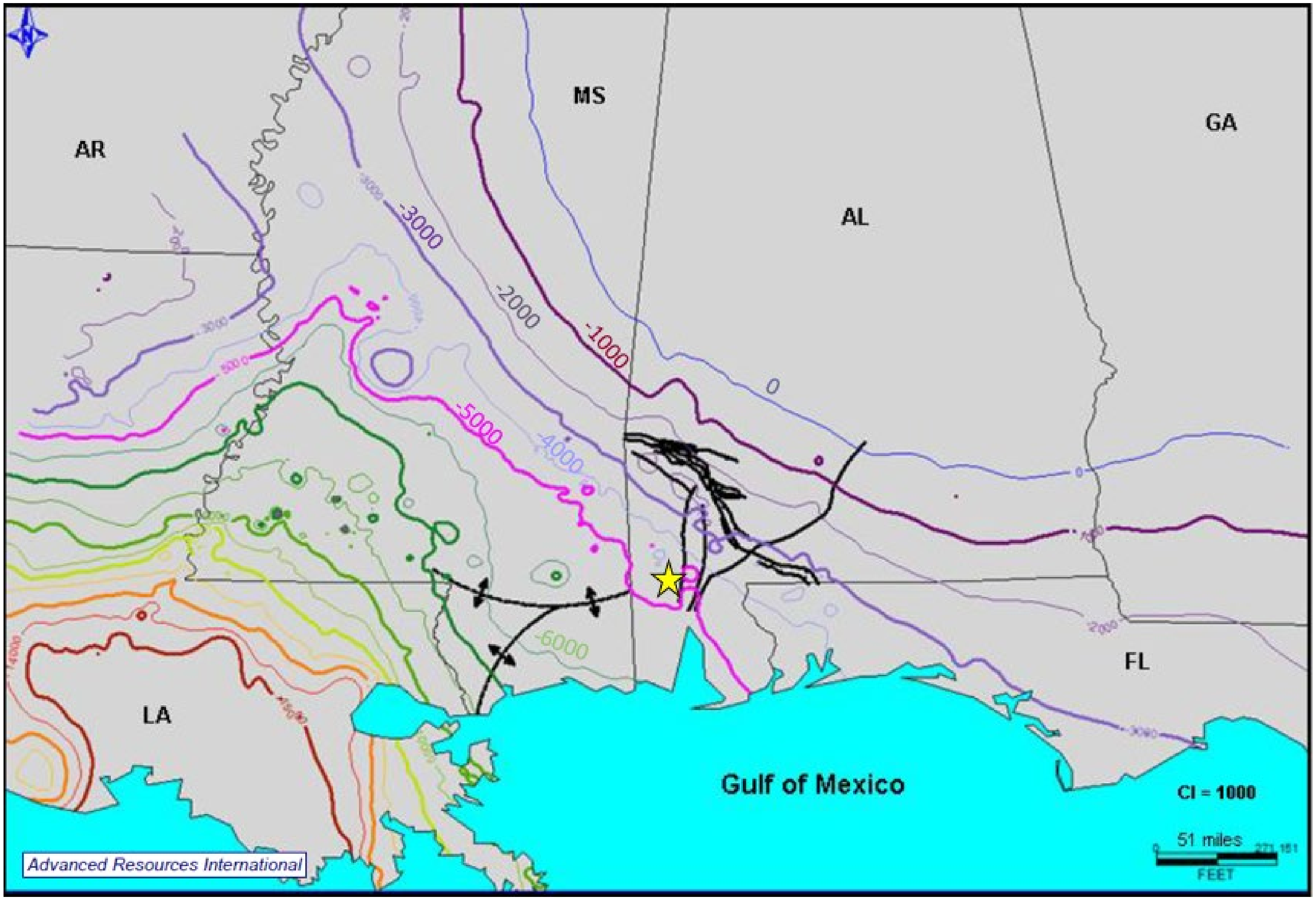


Figure 33. Regional structure contour map on the top of the Selma Group (modified from Petrusak et al., 2009). Datum is elevation in ft. subsea. Location of the Longleaf CCs Hub is starred.

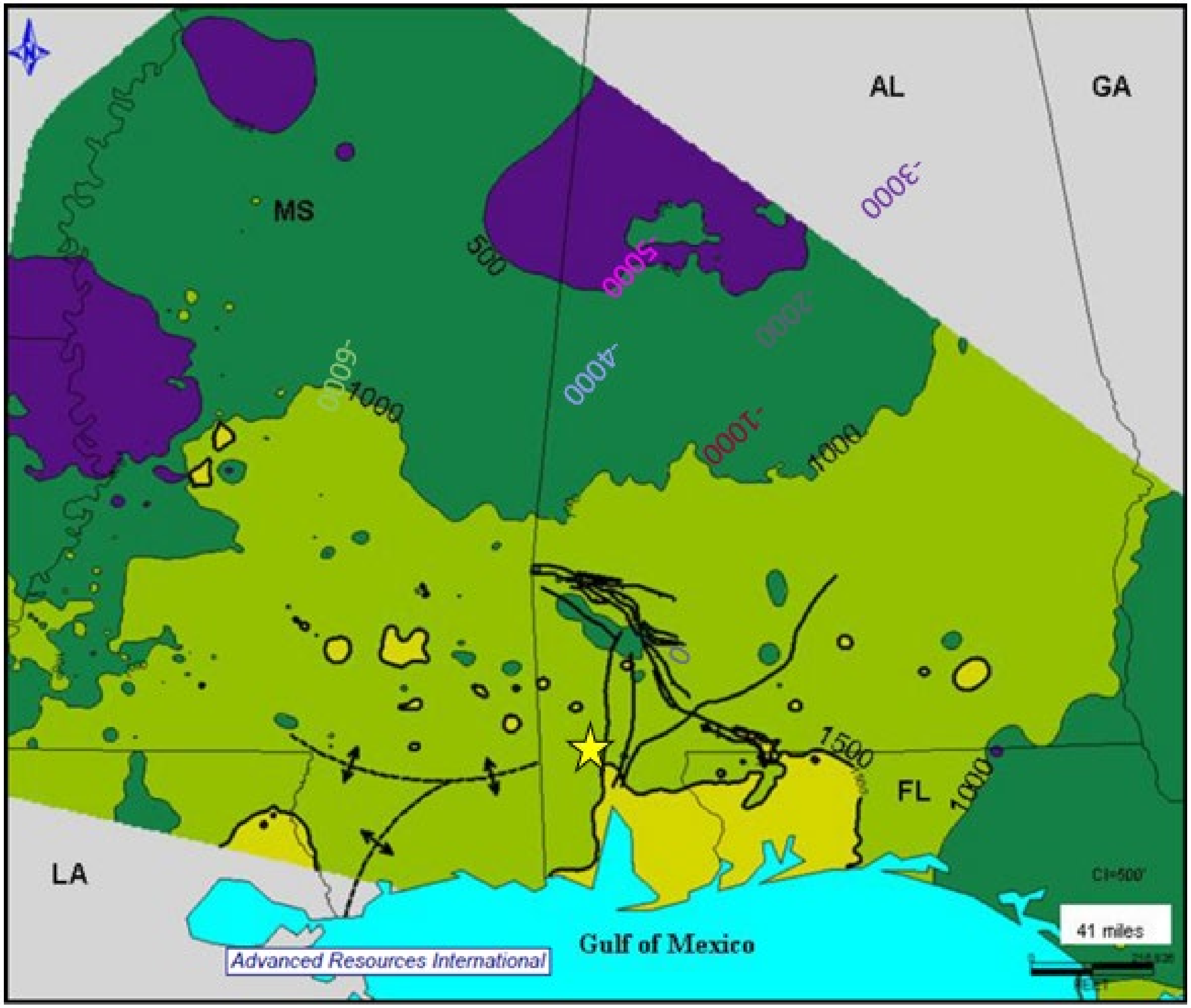


Figure 34. Regional gross isopach map of the Selma Group. In southwest Alabama, the Selma Group is consistently 1,000–1,500 ft. thick (from Petrusak et al., 2009). Location of the Longleaf CCS Hub is starred.

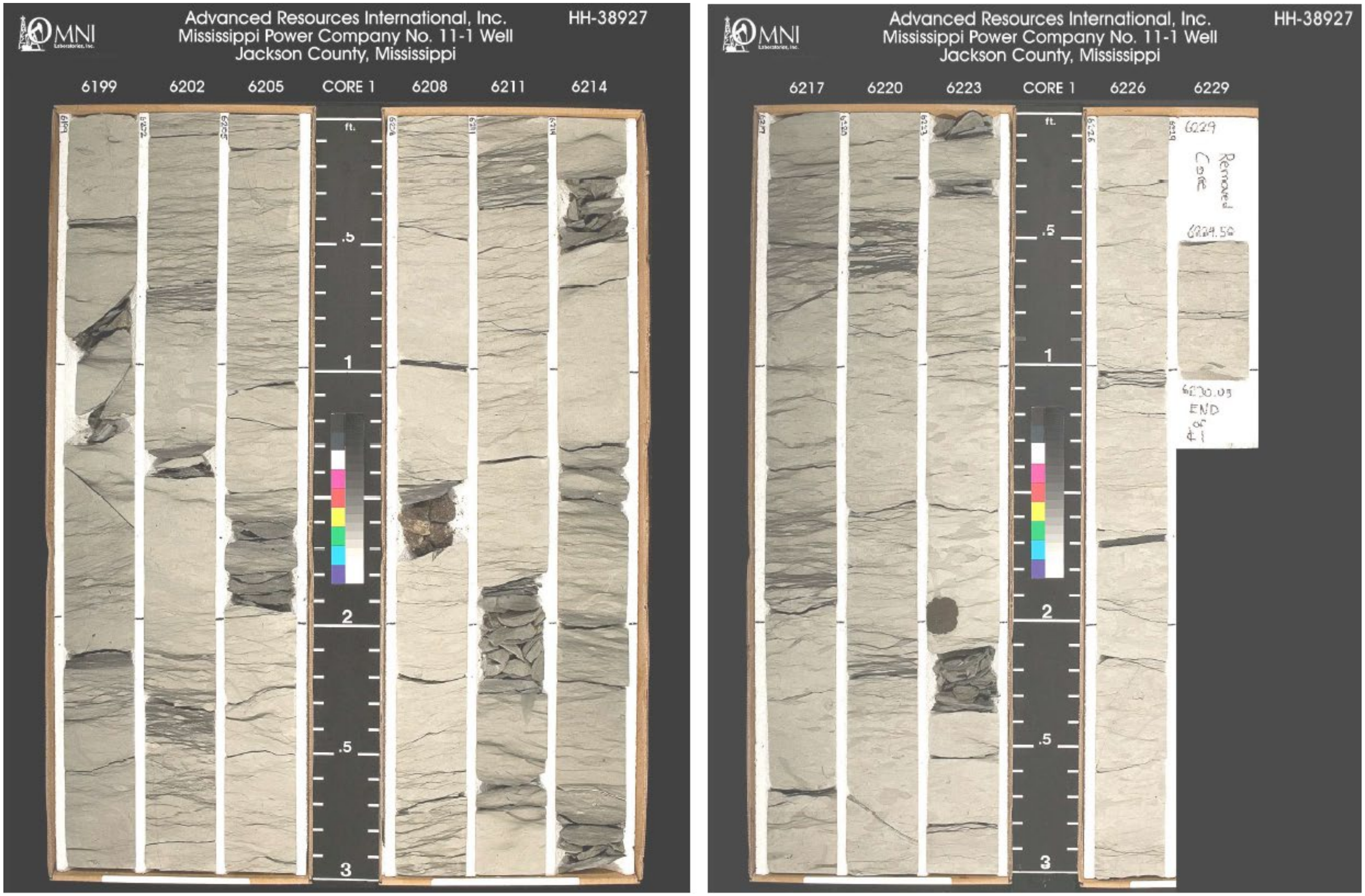


Figure 35. Core photos from the Selma Group in the Mississippi Power Co. #11-1 located approximately 40 miles from the Longleaf CCS Hub (from Petrusak et al., 2009).

B.6. Geomechanical and Petrophysical Information of the Confining Zones [40 CFR 146.82(a)(3)(iv)]

Alabama Gulf Coast region clastic reservoirs typically have moderate fracture pressure gradients, with conservative regional fracture pressure gradient estimates of 0.7 to 0.75 psi per foot. Modeling work in support of this permit application used 90% of the regional fracture gradient of 0.63 psi/ft. Note that pressure gauges installed at 9,355 ft (bottom of injection tubing) in the D-9-7 #2 well during the Phase III SECARB CO_2 injection demonstration reached sustained pressures of 5,850 psig (0.625 psi/ft) with no issues observed in terms of reservoir geomechanical impact. The **AoR and Corrective Action Plan** details current assumptions regarding formation temperature, pressure, and pore pressure gradient. The resulting computational modeling used 0.63 psi/ft as the maximum allowable downhole pressure gradient to determine the CO_2 injection rate, the surface CO_2 injection pressure, and the CO_2 mass that can be injected at the Longleaf CCS Hub.

A site-specific geomechanical characterization effort is planned with the use of micro-image logs, wireline well tests, and laboratory core tests as detailed in the **Pre-Operational Testing Plan**. Acquisition of this data will be undertaken during the construction of new monitoring and injection wells in the storage area. Physical properties that will be determined from samples collected from these wells include bulk density, porosity, permeability, Young's modulus, Poisson's ratio, and failure strength, to determine:

- Fracture/parting pressure of the sequestration zone and primary confining layer, and the corresponding fracture gradients are determined via step rate or leak-off tests.
- Rock compressibility, or measure of rock strength, for the confining layer(s) and sequestration zone.
- Rock strength and the ductility of the confining layer(s).
- Unconfined compressive strength (UNC) of the confining layer as measured from intact samples.

B.7. Seismic History [40 CFR 146.82(a)(3)(v)]

The Longleaf CCS Hub sits within a tectonically stable passive margin with no known sources of natural seismicity in the AoR or region. The USGS published National Seismic Hazard Map shows the frequency of damaging earthquake shaking expected in a 10,000-year period (**Figure 36**). The Longleaf CCS Hub has a low risk of damaging earthquakes, with 2 to 4 expected within a 10,000-year period.

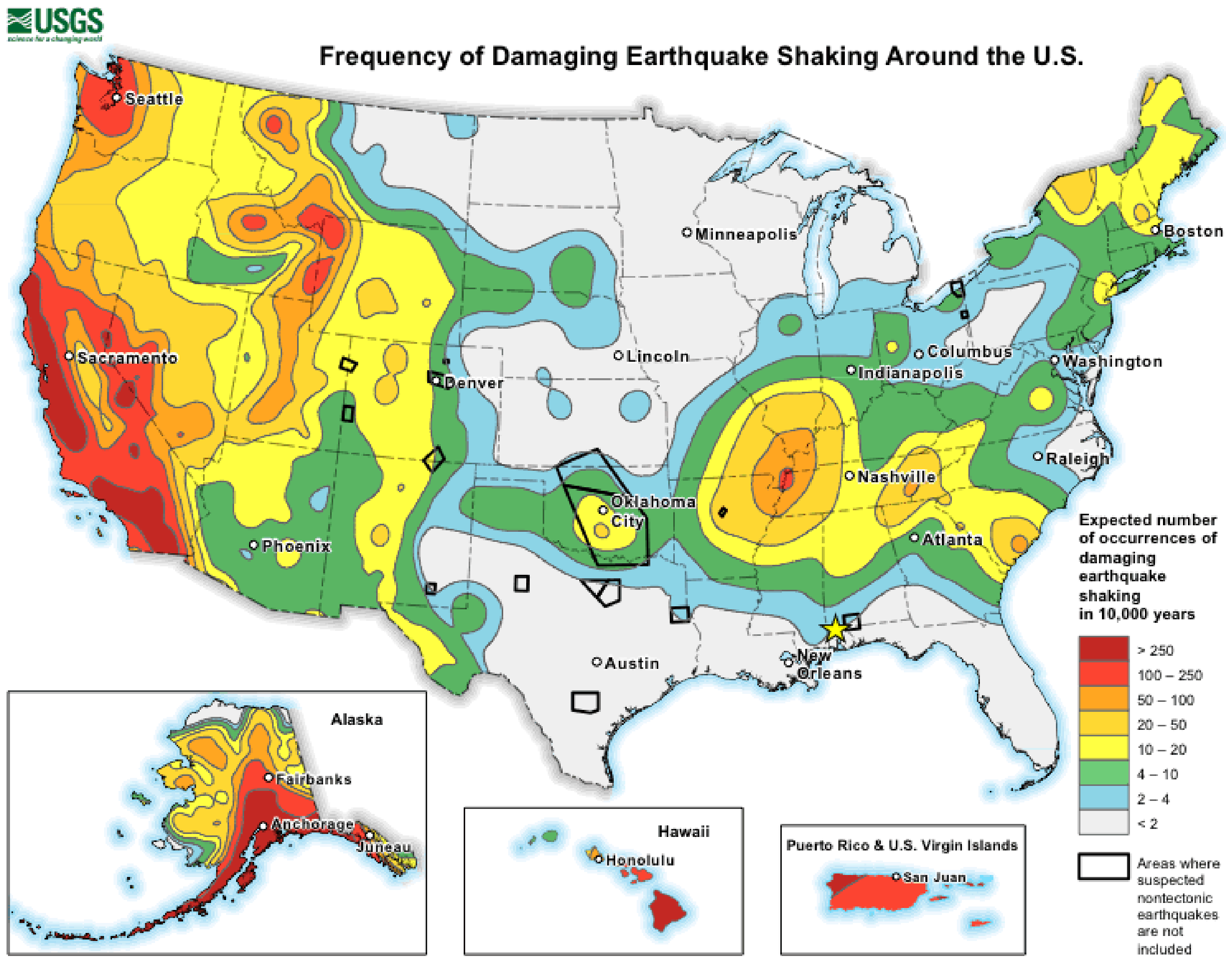


Figure 36. USGS Seismic Hazard Map showing the frequency of damaging earthquake shaking within a 10,000-year period (Petersen et al., 2008).

Longleaf CCS Hub is indicated by the star on the map in southwest Alabama.

Southwestern Alabama is in a region of low natural seismicity, and any earthquakes that do occur are of low magnitude. No earthquakes above Intensity VII on the Modified Mercalli Scale (severe damage to older structures, slight damage elsewhere) have occurred in Alabama during historical times (Bolt, 1993). **Figure 37** illustrates the peak ground acceleration (as a percentage of the gravity constant 9.8 m/s^2) with a 2% likelihood of being exceeded within a 50-year period in Alabama. The peak ground acceleration for Mobile County is estimated to be 4 to 6 percent gravity which would correlate to a Modified Mercalli Intensity of VI or less causing only slight damage to older structures.

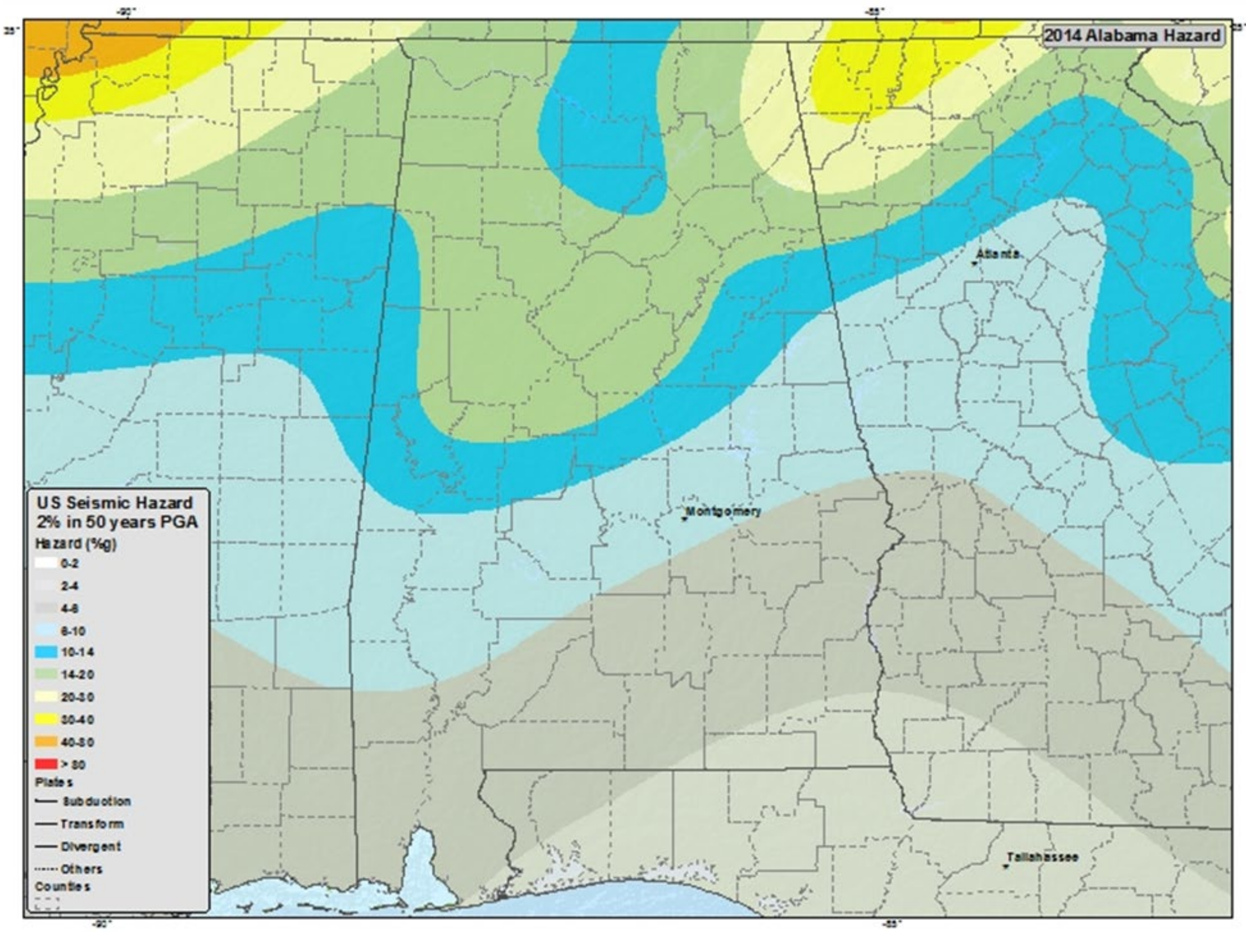


Figure 37. 2014 Seismic Hazard Map of Alabama from the USGS National Seismic Hazard Maps illustrating the peak ground acceleration with a 2% likelihood of being exceeded within a 50-year period (US Geological Survey, 2014).

The largest earthquake in Alabama's history occurred on October 18, 1916, in Irondale, Jefferson County (approx. 190 mi. NE of the Longleaf CCS Hub) and had an estimated magnitude of 5.1 on the Richter scale (Mercalli index of VII). The largest earthquake in south Alabama occurred in Escambia County in 1997 along the Bahamas Fracture Seismic Zone (approx. 45 mi. from the Longleaf CCS Hub), measuring 4.9 on the Richter scale (Mercalli index of VI). It has been suggested that this earthquake may have been non-tectonic, instead triggered as a poroelastic response of the crust to the extraction of hydrocarbons or associated wastewater injection in the area (Gomberg and Wolf, 1999). No earthquakes have been recorded in Mobile County, the site of the Longleaf CCS Hub (Ebersole, 2007). Thus, the likelihood of an earthquake capable of causing considerable damage within the storage area (Mercalli index of IX—ground cracks, pipes break, foundations shift) is very low.

B.8. Hydrogeologic Information/Maps and Cross Sections of USDWs [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

B.8.1. Base of USDW

EPA defines protected USDWs as aquifers with a TDS content less than 10,000 mg/L. Only limited information on the composition of deep groundwater is available at the Longleaf CCS Hub. However, the Stauffer Chemical Company's plugged and abandoned Class I injection well located in Bucks, Alabama about six miles south from center of the Longleaf CCS Hub identified the Chickasawhay Limestone at 1,440 ft., a fossiliferous, arenaceous, and glauconitic limestone, as the deepest USDW in northern Mobile County (Tucker and Kidd, 1973; Class One Injection Well Survey, 1986; Mancini et al., 1999).

Limited data on the depth of the Chickasawhay in the Longleaf CCS Hub is available, but the deepest USDW data point, located in the northeastern part of the of the geologic model area, occurs at depth of approximately 1,605 ft. based on Geological Survey of Alabama (GSA) published maps (**Figure 38**) (Gillett et al., 2000).

Considering the uncertainty in the depth of the base of the Chickasawhay, a conservative estimate for the base of USDW across the storage area is 1,700 ft. The Chickasawhay Formation and shallower freshwater aquifers are protected from underlying saline reservoirs by the Bucatunna Clay in the Byram Formation within the Vicksburg Group. The Bucatunna Clay is typically over 100 ft. thick in the region and is considered an effective confining unit separating the deeper saline water from the USDW in the Chickasawhay (**Figure 39**) (Alverson, 1970).

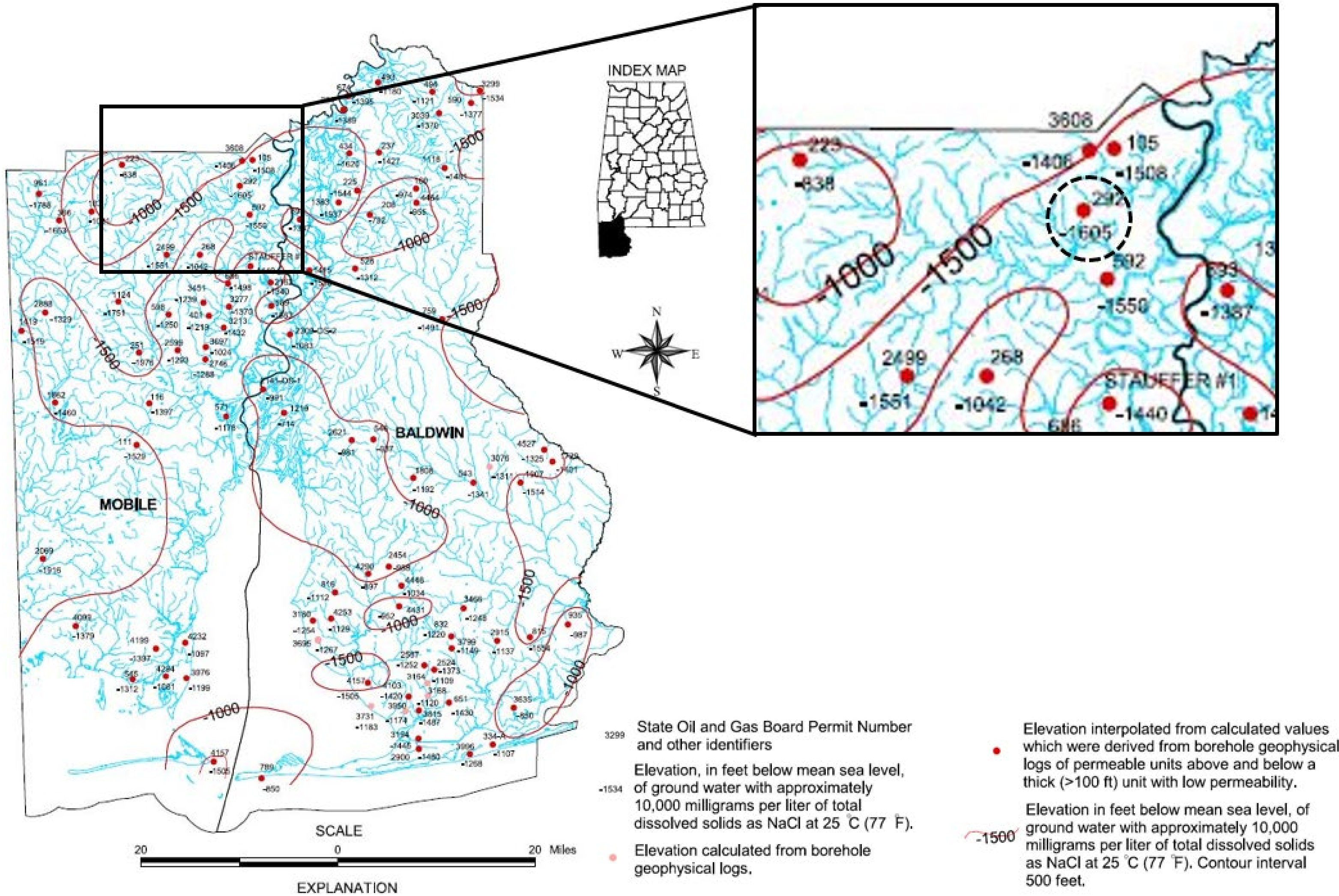


Figure 38. GSA published map (Gillett et al., 2000) of the base of USDW defined as 10,000 mg/L TDS or less. Inset map shows deepest data point near the Longleaf CCS Hub at 1,605 ft below sea level (dashed circle).

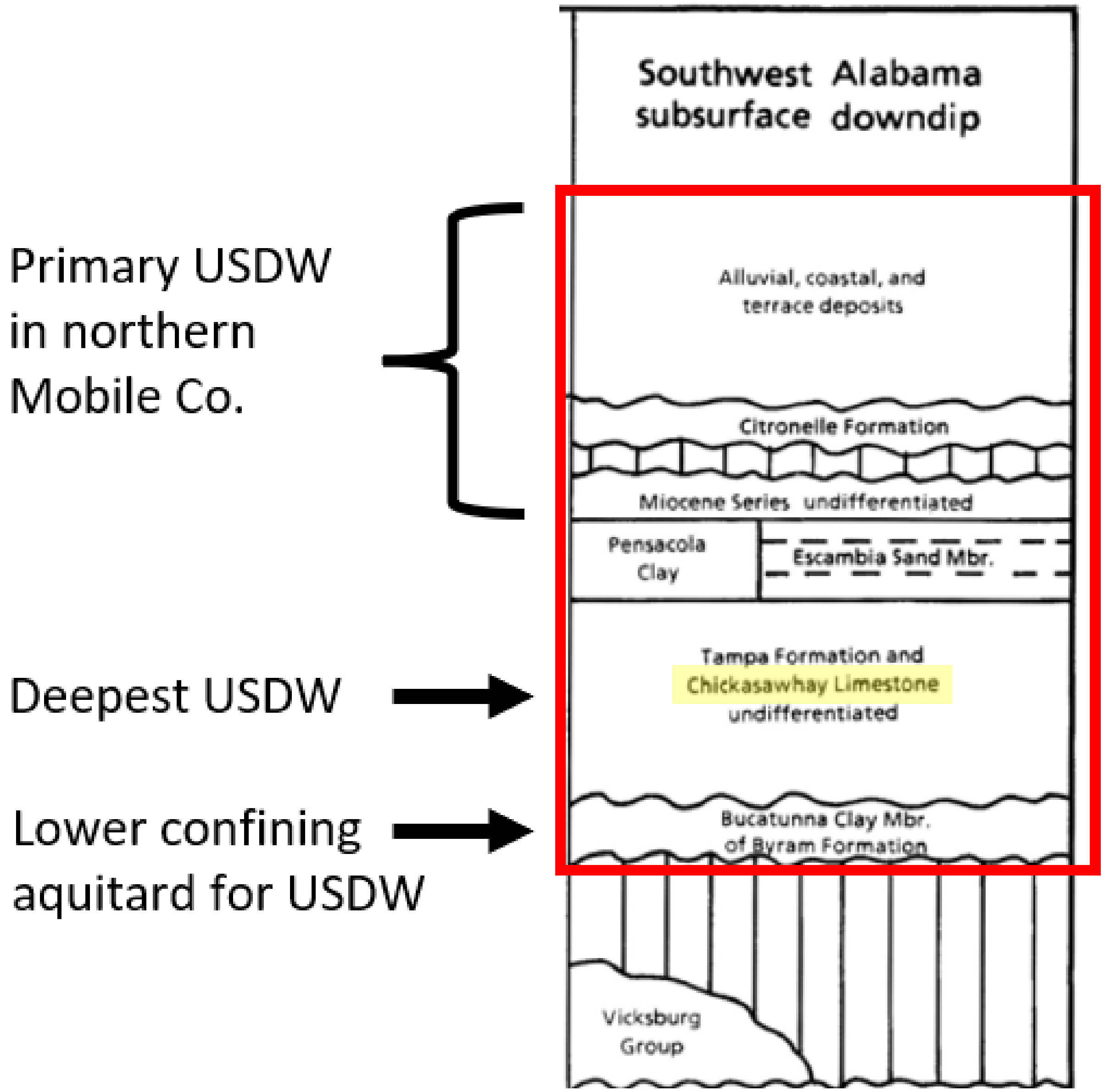


Figure 39. Stratigraphic column of USDW and the freshwater aquitard protecting USDW in southwest Alabama (modified from Raymond et al., 1988).

Below the Chickasawhay Formation, all aquifers in the area are saline with TDS content exceeding 10,000 mg/L (Pashin et al. 2008). These deep saline reservoirs include sandstones in the Claiborne Group, Wilcox Group, Eutaw Formation, Tuscaloosa Group, Wash-Fred undifferentiated, and the Paluxy Formation.

The saline reservoirs in the Claiborne and Wilcox Groups contain prolific aquifer up dip to the north. In Washington County, about 20 miles north of the Longleaf CCS Hub, the Claiborne and Wilcox Groups may contain potable water and are referred to as the Pearl River Aquifer by the USGS (**Figure 40**) (USGS, 1998).

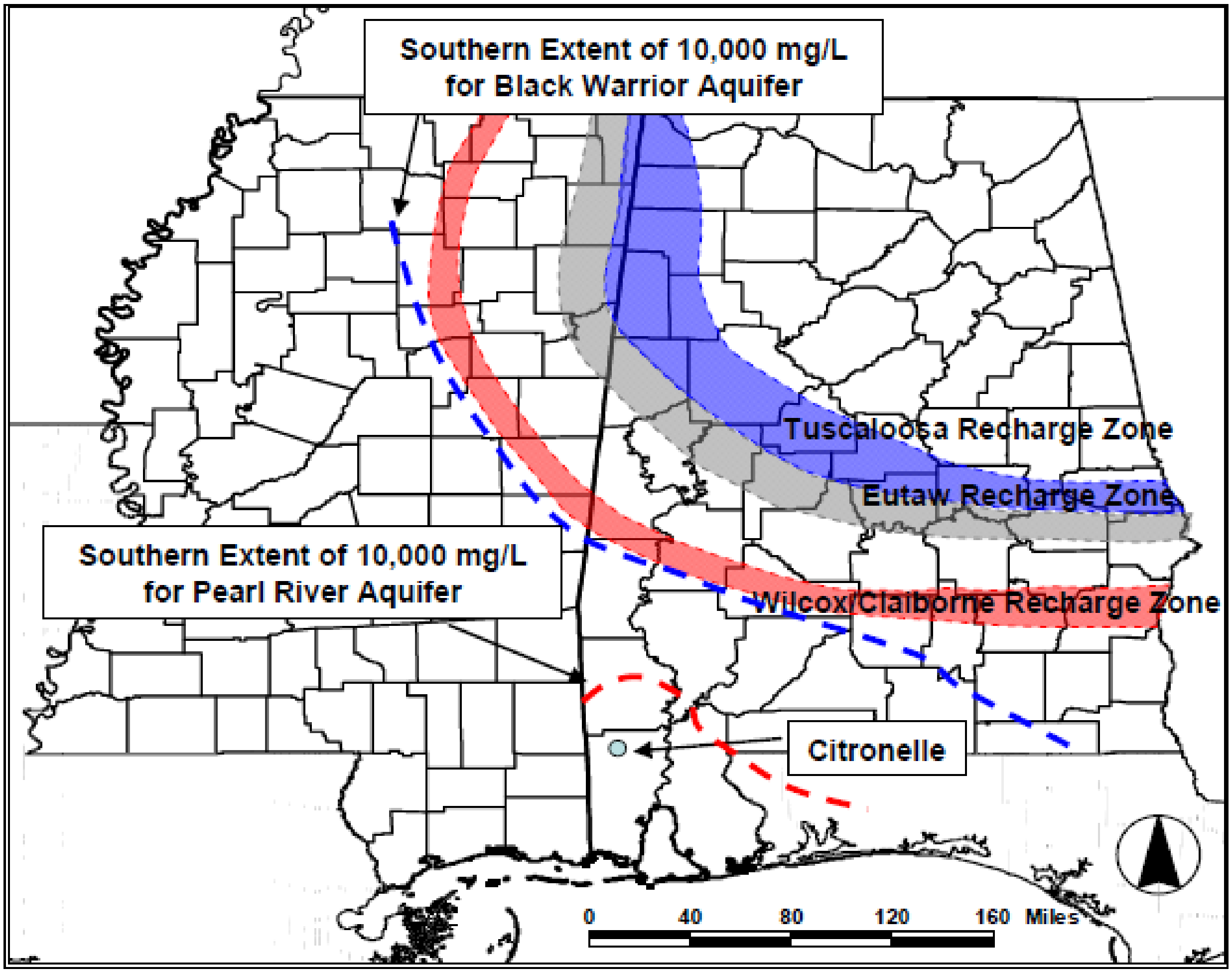


Figure 40. Map of downdip freshwater extent of the Claiborne/Wilcox-aged Pearl River and Eutaw/Tuscaloosa-aged Black Warrior River Aquifers (Modified from USGS, 1998).

The next major aquifer system is the Eutaw-Tuscaloosa “Black Warrior River” aquifer (USGS, 1998). The Black Warrior River aquifer contains potable water in portions of central Alabama, becoming a USDW about 80 miles north of the Longleaf CCS Hub (**Figure 40**).

None of the deeper saline aquifers, including those in the Wash-Fred and the Paluxy Formations, are used as sources of freshwater in Alabama (Raymond et al., 1988), and since the lower Cretaceous subcrops in the eastern Gulf of Mexico Basin, they do not have a surface freshwater recharge zone in the region.

B.8.2. Regional Hydrogeologic Information

The primary water supply within northern Mobile County is from the Plio-Pleistocene, Miocene, and Oligocene-aged units, including the Plio-Pleistocene Watercourse Aquifer and the Miocene-Pliocene Aquifer (Gillett et al., 2000). Lithologic and hydrologic descriptions of these aquifers are provided in **Table 7**.

Large capacity wells tapping the Miocene-Pliocene Aquifer in Mobile County typically range from 150 to 800 feet deep and may yield one million gallons of water per day or more. Additionally, many residential and agricultural users obtain water from the shallow Watercourse Aquifer, which is a water-table (unconfined) aquifer consisting of interbedded sand, gravel, and clay. Wells screened in the Watercourse Aquifer are typically less than 150 feet deep and yield on the order of 100 gallons per minute.

A USGS flow model of the Wilcox aquifer along the eastern Gulf Coast suggests that groundwater migrates down dip from recharge zones located to the north (where the strata outcrop) and becomes parallel to the coast moving eastward in southern Mississippi (USGS Open-File Report 91-451). The model results suggest that Gulf Coast saline reservoirs such as the Wilcox have a maximum velocity of 1 to 10 ft per year. The hydrologically sheltered Paluxy saline formation is expected to have substantially lower groundwater velocities.

Figure 41 shows a generalized cross section of the principal freshwater formations in southwest Alabama. The municipal water source in the area is lower Miocene sands, which are shallower than 900 ft. within the Longleaf CCS Hub. Based on this regional study and the structural dip of the formations, we expect groundwater flow to move to the south-southwest towards the Gulf of Mexico through the AoR (**Figure 42**).

Table 7. Description of aquifers in Mobile and Baldwin Counties, southwestern Alabama (from GSA report, Gillet et al., 2000)

Hydrogeologic unit	Unit character		Aquifers		
	Lithologic	Hydrologic	Walter & Kidd, 1979	Chandler & others, 1985	This report
Pleistocene (?)-Holocene	Sand, white to pale-orange, fine- to coarse-grained; silt; clay; and sea-shell hash. Finer grained sediments predominant in lower part of unit as dis- continuous layers.	Predominantly medium-grained sands in upper 20 to 60 feet of unit comprise principal aquifer. The aquifer is a water-table aquifer and is a potential source of more than 100 gpm of water per well.	Beach sand aquifer	A1	Watercourse aquifer
Pleistocene-shallow Miocene	Sand, white to light-gray, fine- to very coarse-grained, gravelly and carbonaceous in places, interbedded with sandy silty clay.	Sand and gravel in unit comprise major aquifers. The lower aquifers are generally semiconfined. Potential source of 100 to more than 100 gpm of water per well.	Gulf Shores aquifer	A 2	Miocene-Pliocene aquifer
Deep Miocene	Same as A2, except sediments form more persistent and traceable layers in the sub- surface. The siliciclastics im- mediately overlie the Pensacola Clay.	Major aquifers are semi-confined or confined and yield water to wells under low-head artesian pressure. Potential source of more than 1,500 gpm of water per well.	350- and 500-foot aquifers	A 3	

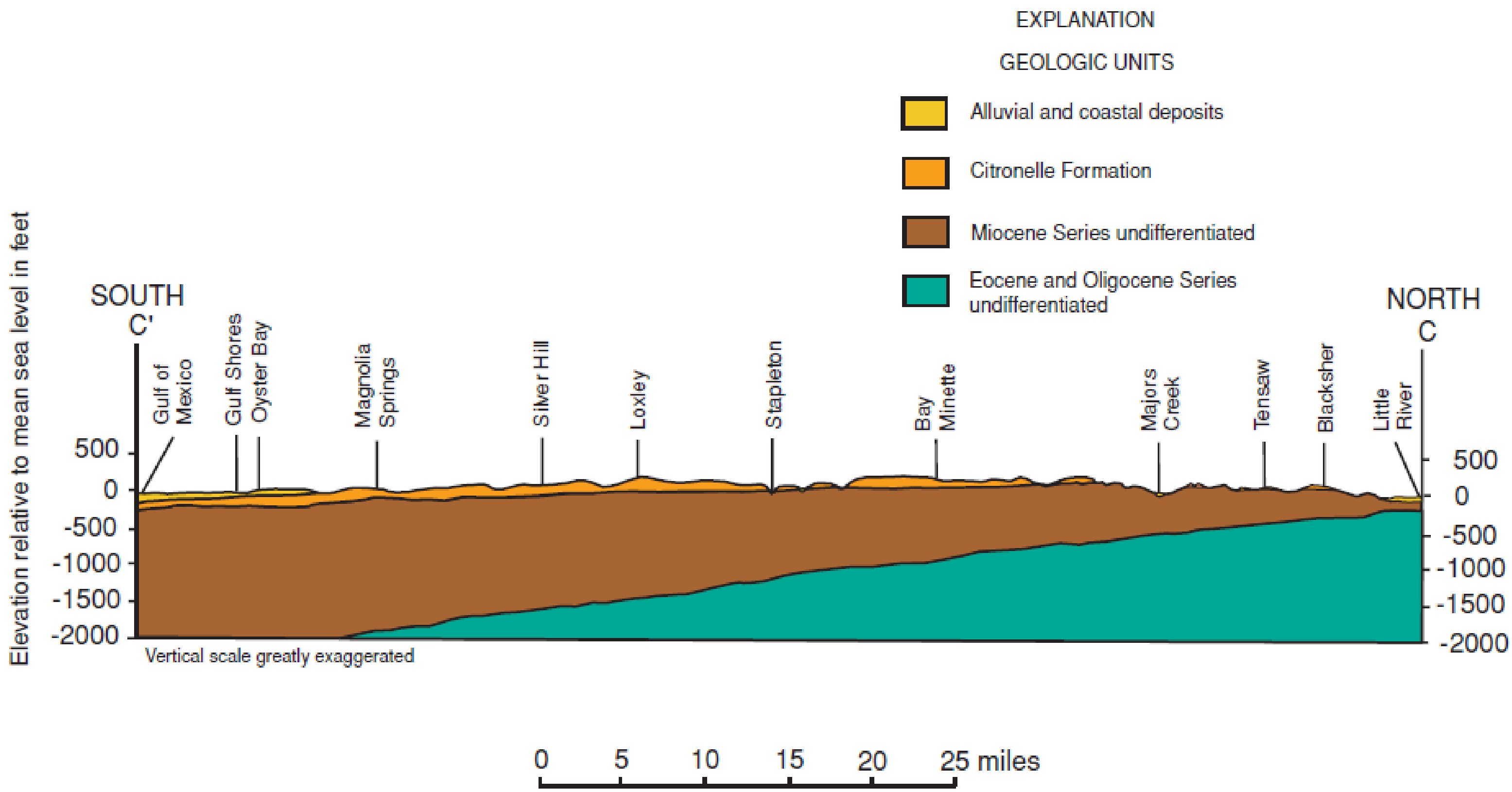


Figure 41. Generalized cross section of freshwater formations within southwest Alabama from the Geological Survey of Alabama (Gillett et al., 2000).

Cross section C-C' is oriented North to South through western Baldwin County; the Longleaf CCS Hub is located approximately 20 miles west of Major's Creek.

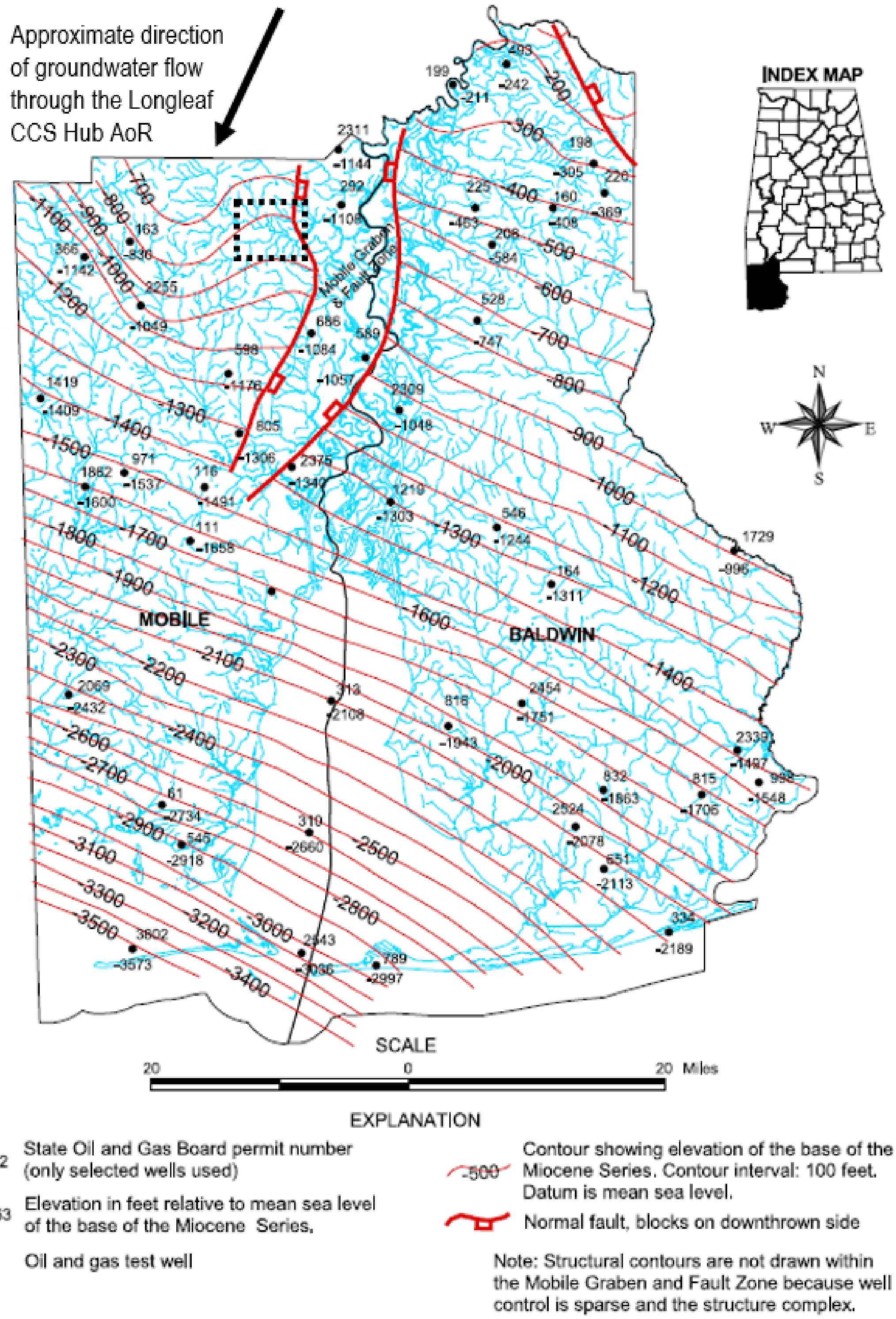


Figure 42. Structure contour map on the base of the Miocene series from the GSA (Gillett et al., 2000). The dashed black box is the approximate location of the Longleaf CCS Hub.

B.8.3. Water Wells within the Longleaf CCS Hub

Within the Longleaf CCS Hub, only the Watercourse and Miocene-Pliocene Aquifers are used for groundwater. A total of 97 water wells (eight of which are in the AoR) are drilled within the project area and are completed in either the Miocene undifferentiated sands or the Citronelle Formation (**Figure 43**). According to the GSA Risk-Based Data Management System-Environmental (RBDMS-ENV), all water wells in the area are drilled to 1,000 ft. or shallower except for one drilled to 6,895 ft. that did not penetrate the primary upper confining interval, the Tuscaloosa Marine Shale at 8,000 ft. (Water well No. 097J43001). While there is no wellbore construction information publicly available, well No. 097J43001 was likely drilled as a deep exploration well then plugged back and converted to a water well. This well is located approximately four miles southeast of the center of the Longleaf CCS Hub. All municipal water wells are completed between 700 and 800 ft. or shallower, separated by the underlying Bucatunna Clay from deeper reservoir intervals.

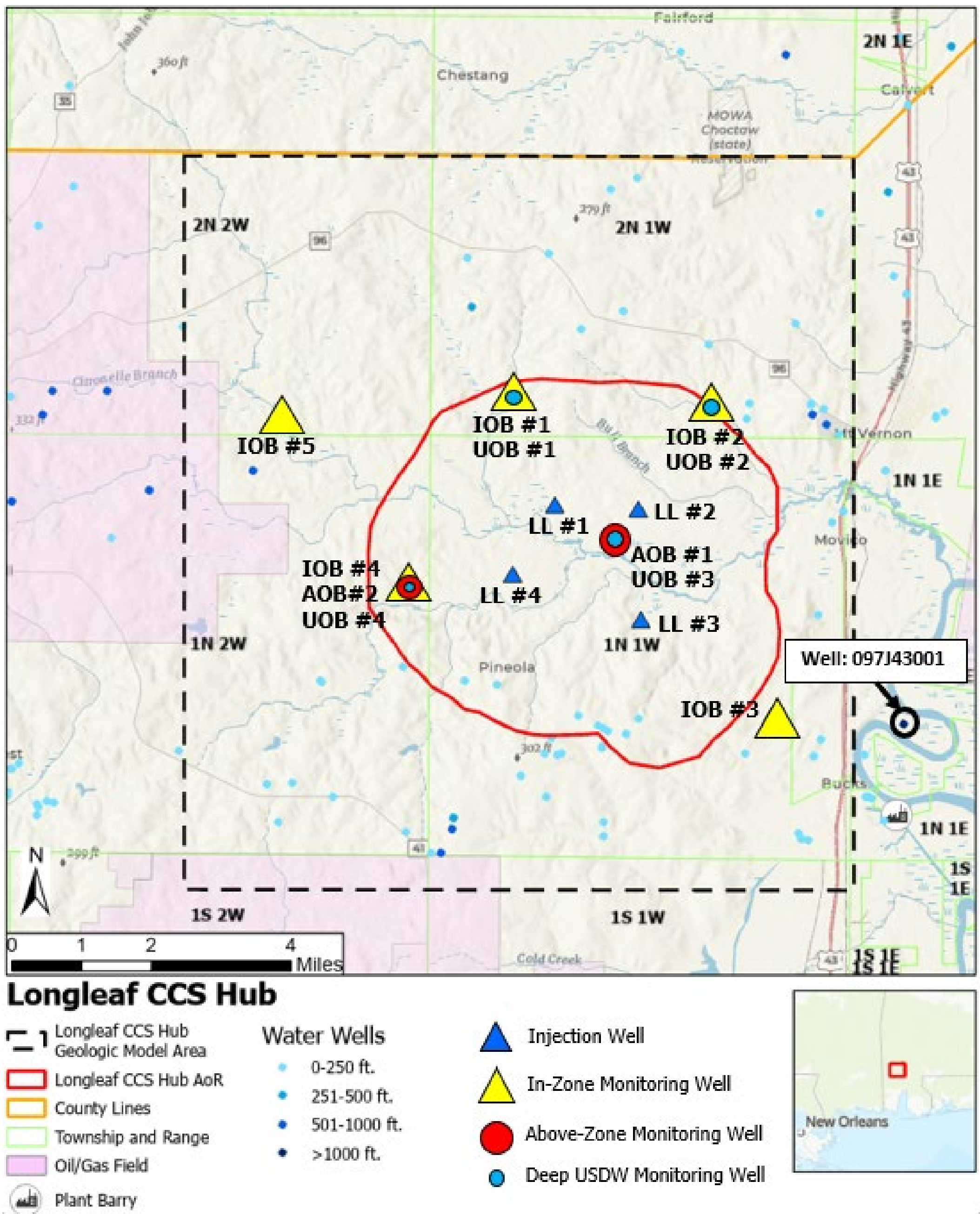


Figure 43. Map of groundwater wells around the Longleaf CCS Hub.

Water well location data from the Geological Survey of Alabama Risk-Based Data Management System-Environmental (RBDMS-ENV). Well No. 097J43001 (reported TD of 6,895 ft) is circled.

B.9. Baseline Geochemical Data [40 CFR 146.82(a)(6)]

Reservoir fluid samples from the Upper Paluxy at 9,400 ft to 9,430 ft were gathered as part of the SECARB Phase III CO_2 injection demonstration at Citronelle Dome and are representative of the Paluxy reservoir fluids at the Longleaf CCS Hub. This work showed that TDS in the Paluxy ranged from 185,000 to 203,000 mg/L (Conaway et al., 2016).

Additional fluid-phase geochemical data will be collected as part of the **Pre-Operational Testing Plan**. Specifically, water samples will be collected from the Chickasawhay Formation, the lower-most USDW in the area, as well as the Paluxy, Tuscaloosa, and Eutaw formations to provide site-specific measurements of fluid geochemistry.

Solid-phase petrological analyses for the Paluxy Formation are discussed in detail in **Section B.2.** Additional formation mineralogy data for the Tuscaloosa Marine Shale and the Wash-Fred Basal Shale will be obtained from logs and core samples collected during injection and monitoring well drilling at the Longleaf CCS Hub.

B.10. Site Suitability [40 CFR 146.83]

The geologic site characterization of the Longleaf CCS Hub in northern Mobile County, Alabama along with information assembled by other studies show that the project area provides a geologically favorable setting for safe, long-term storage of CO_2 (Esposito et al., 2008; Pashin et al., 2008; Esposito et al., 2010; Koperna et al., 2012). The primary CO_2 injection interval within the lower Cretaceous strata is the Paluxy Formation that contains a series of thick and porous fluvial sandstones and interbedded floodplain mudstones.

The Paluxy Formation has previously demonstrated the capability for geologic sequestration of CO_2, serving as the primary injection interval for the SECARB Phase III CO_2 injection demonstration at Citronelle Dome, five miles from the center of the proposed injection wells. Data collected from that project combined with other information indicate there is 473 ft of high porosity and permeability saline reservoir sandstone that will be perforated for CO_2 injection in the planned injection wells for the Longleaf CCS Hub. These injection intervals are separated into two zones, the Upper and Lower Paluxy. Average porosity for the sandstone intervals to be perforated in the Upper Paluxy is 13%, ranging from 8 to 19%, and average permeability is 125 mD ranging from 26 to 437 mD. For the Lower Paluxy, average porosity is 12% ranging from 8 to 16%, and average permeability is 60 mD ranging from 24 to 115 mD. Based on these characteristics, the estimated static storage resource of the Paluxy Formation at the Longleaf

CCS Hub is 2.3, 4.3, and 7.4 Mt per $mi.^2$ for storage efficiency factors of 7.4%, 14%, and 24%, respectively.

The primary confining unit for the Longleaf CCS Hub will be the Tuscaloosa Marine Shale. This 300 ft thick shale has an average effective porosity of less than 2% and permeability at the microdarcy to nanodarcy scale. The low permeability and absence of reactive minerals (e.g., Calcite) provides effective sealing characteristics to prevent the vertical migration of CO_2 into overlying formations. The Wash-Fred Basal Shale, directly overlying the Paluxy Formation, will serve as the secondary confining unit. The shale has an average effective porosity of less than 3% and permeability generally less than 1.0×10^{-5} mD. The Selma Group and Midway Group serve as additional confining units that will provide supplemental security for USDWs in the area. In total, 8,380 ft of strata separate the top of the primary injection interval and the base of the deepest USDW at 1,700 ft.

Below the Paluxy, the Mooringsport Formation and Ferry Lake Anhydrite, the caprock for petroleum accumulations in the underlying Rodessa Formation at Citronelle Dome, form a 350 ft thick section of low porosity and permeability interval that serves as the lower confining unit for the storage interval.

Further, the lack of faults and existing wellbores in the AoR, and lack of strong natural seismicity in southwestern Alabama make the presence of CO_2 migration pathways into USDW highly unlikely.

The characteristics of the injection and confining units suggest that the lower Cretaceous Paluxy strata of northern Mobile County, Alabama is compatible with the long-term storage of CO_2. Highly porous and permeable sandstones, overlain and underlain by thick intervals of proven sealing units, ensure the prevention of vertical migration of CO_2 out of the Paluxy Formation. Additionally, the regional continuity of the primary and secondary confining units demonstrate that the CO_2 plume will be confined to the Paluxy injection interval.

C. INJECTION WELL CONSTRUCTION DESIGNS

The injection wells have been designed to accommodate the mass of CO_2 that will be delivered to the storage site, considering key characteristics of the CO_2 storage reservoir that affect the well design. This section illustrates the comprehensive analysis performed to comply with and exceed the EPA Class VI UIC well standards regarding the design of the casing, cement, and wellhead [40 CFR 146.86(a)].

C.1 Wellhead Injection Pressure

SLB's *PIPESIM* software was used to conduct a nodal analysis to determine the feasibility of CO_2 injection through 6.625-inch tubing for the CO_2 injection wells. The analysis assumes an expected wellhead (injection) pressure of about 1,500 psia (**Section *D.*4** of the *Injection Well Operations Plan*). The nodal analysis for Injection Wells LL #2, LL #3, and LL #4 used was designed for a surface casing string with a 9.625-inch 53 lb/ft LTC thread casing set at approximately 11,400 feet, with a 6.625-inch 28lb/ft long injection tubing string set at 10,210 feet.

The nodal analysis for Injection Well LL #1 was designed with the same casing construction, however the 6.625-inch tubing will be run from surface to a depth of 10,210 feet. The tubing is then converted to 5.5-inch 23 lb/ft tubing with two sliding sleeves installed to isolate access to the Upper and Lower Paluxy, respectively. Additionally, when both sleeves are fully open, the flow profile is equivalent to the Nodal analysis case with no sliding sleeves (i.e., full access to all of the injection perforations). The injection tubing strings in all four injection wells use L-80 grade steel and 13% chrome type (13Cr-L80). Design parameters from the geologic model are shown in **Table 8** below. The schematics for the casing nodal analysis of both designs is shown in **Figure 44**.

Table 8. Zonal Inputs for Nodal Analysis

	Perforated Interval	Top (ft)	Bottom (ft)	Mid Point (ft)	Gross Thickness (ft)	Net Thickness (ft)	Pressure (psi)	Average Permeability (md)	Reservoir Temp (F)
Depth of Caprock	NA	10,125	10,220	10,173	95		4,710	7.0E-05	233
Unperforated Paluxy Shale Interval	NA	10,220	10,269	10,245	49		4,743	5.2E-03	234
Upper Paluxy	1	10,269	10,318	10,294	49	49	4,766	233	235
	2	10,351	10,400	10,376	49	49	4,804	172	236
	3	10,433	10,743	10,588	310	198	4,902	106	240
	4	10,809	10,956	10,883	147	99	5,039	87	245
Lower Paluxy	5	11,191	11,217	11,204	26	26	5,187	31	250
	6	11,295	11,347	11,321	52	52	5,242	75	252

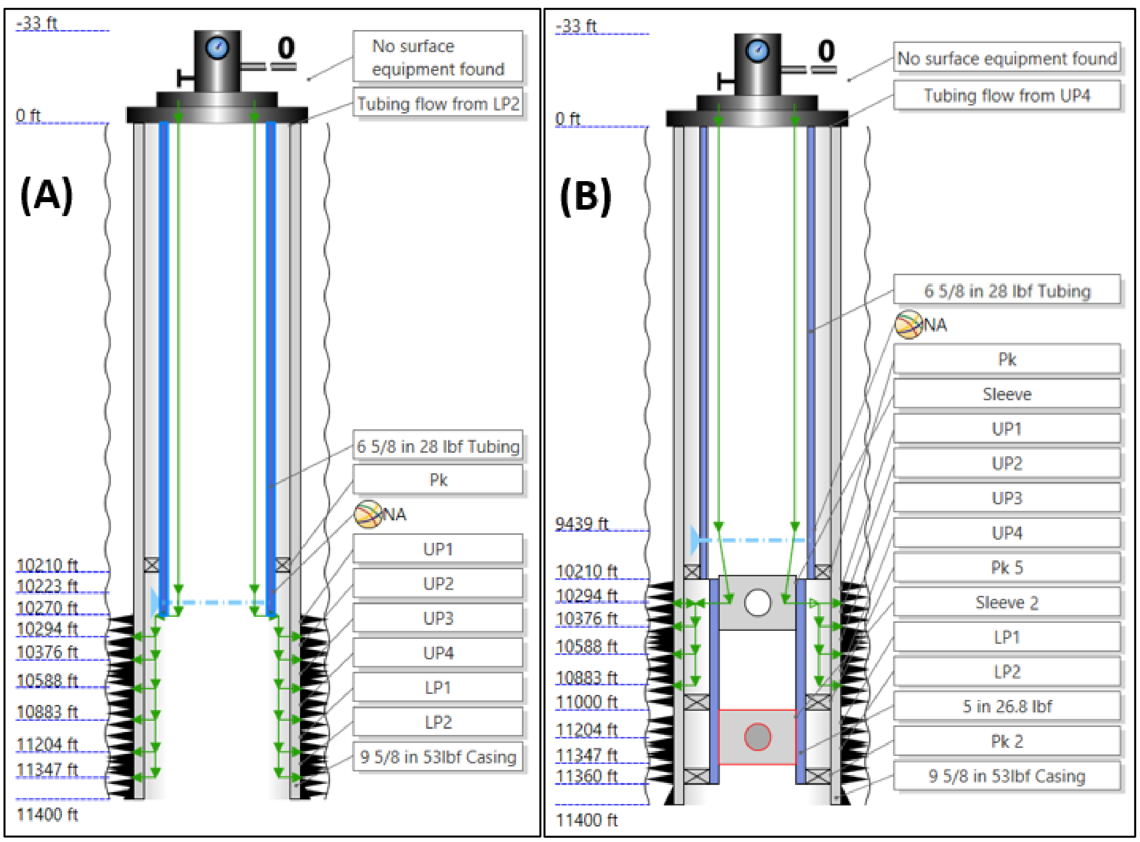


Figure 44. (A) Nodal Analysis Design, LL #2-4 Schematic[1], (B) Nodal Analysis Design, LL #1 Schematic

[1] Surface equipment was not included in the model since it has no effect on downhole flow profiles.

At an injection rate of 1.25 MT/y, the resulting wellhead pressure (no sliding sleeves) is expected to be 1,491 psia, which conforms to the expected delivery pressure (**Figure 45**). If the injection rate momentarily spikes, an injection rate of 1.50 MT/y results in a wellhead pressure of 1,534 psia (**Figure 46**).

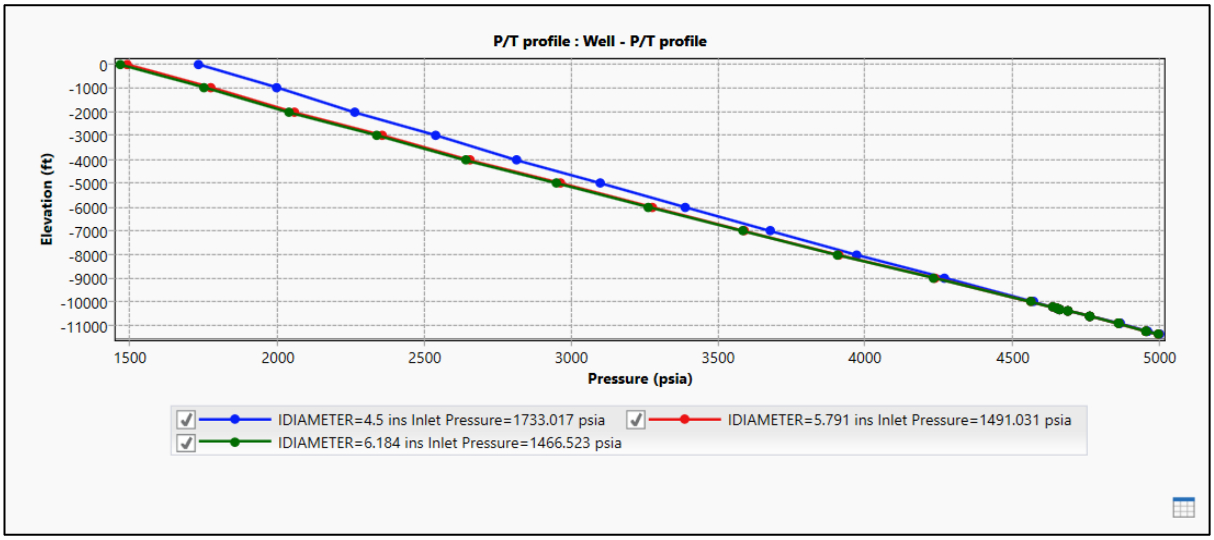


Figure 45. Wellhead Pressure at 1.25 MT/y (No sliding sleeves)

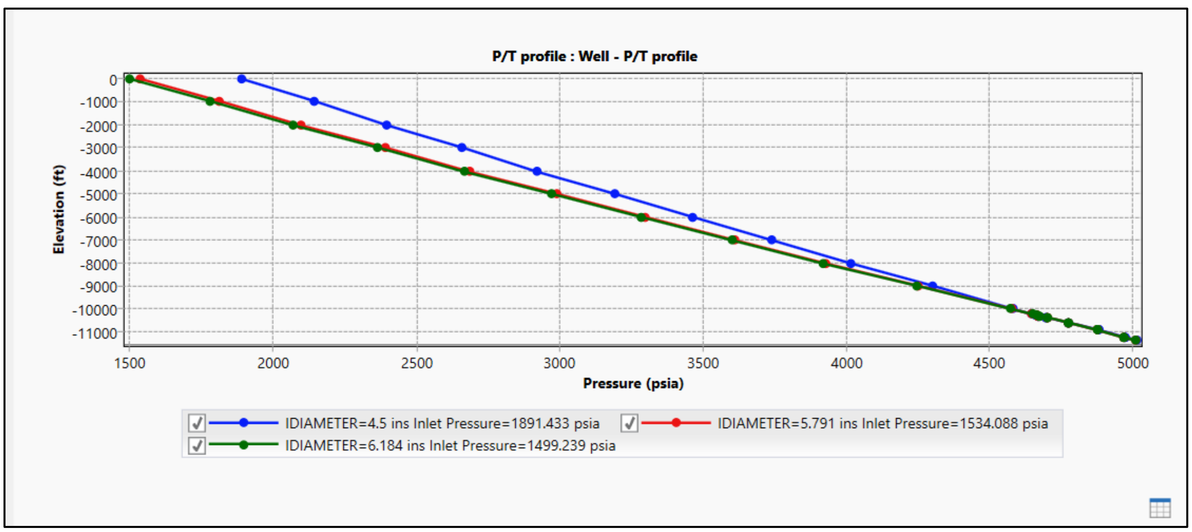


Figure 46. Wellhead Pressure at 1.50 MT/y (No sliding sleeves)

In a situation where the sleeve accessing the Lower Paluxy is closed, and only the Upper Paluxy is open to injection, the tubing is still able to support an injection rate of 1.25 MT/y, with a wellhead pressure of 1,500 psia (**Figure 47**). However, if the Upper Paluxy sleeve is closed, and only the Lower Paluxy sleeve is open to injection, an injection rate of 0.25 MT/y results in a wellhead pressure of 1,465 psia (**Figure 48**). Maximum injection wellhead pressure is set forth in **Section *D.5*.**

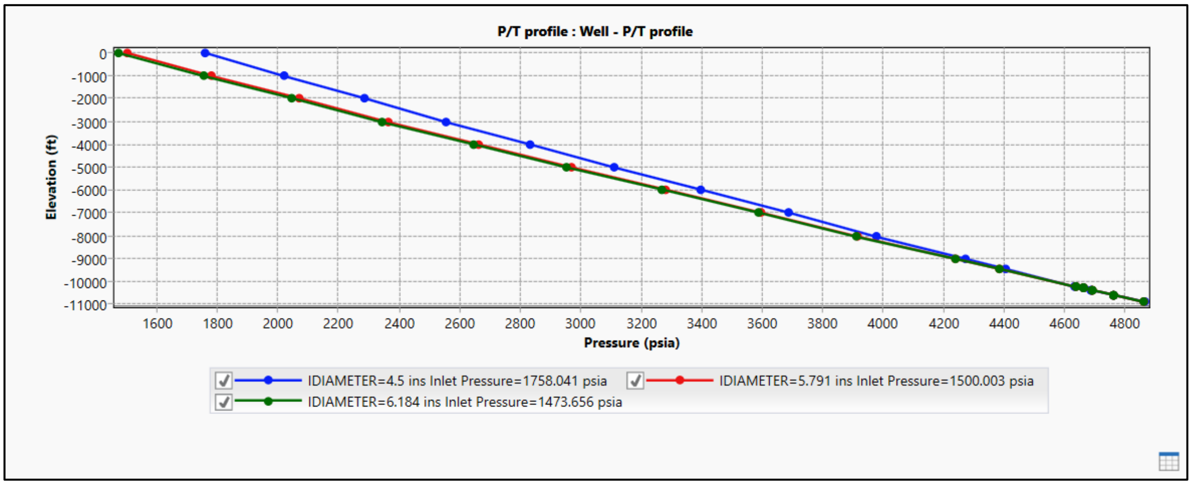


Figure 47. Upper Paluxy Only, Wellhead Pressure at 1.25MT/y

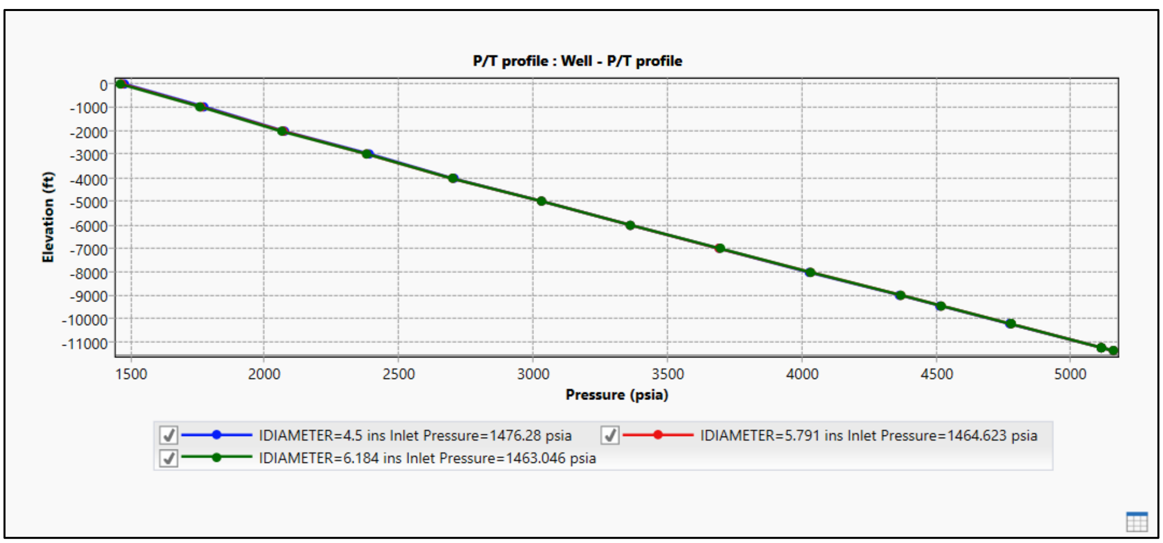


Figure 48. Lower Paluxy Only, Wellhead Pressure at 0.25 MT/y

C.2 Casing Program

Nodal analysis aided in the development of an injection well design to accommodate a 6.625-inch outer diameter (OD) tubing. Additionally, the injection wells have been designed to accommodate the concentric casing sizes required to isolate the injection reservoir from USDWs. Material for the casing was selected to be appropriate for the fluids and stresses encountered within the well [40 CFR 146.86(b)(1)]. For instance, casing strings that will be exposed to injected CO_2 will be 13Cr-L80 steel, which is resistant to corrosion from CO_2.

Lab results have shown the corrosion rate of 13Cr steel in the high-temperature steam environment was less than 0.04 mm/a (Guoqing Xiao, 2020), which is sufficient to retard metallurgical corrosion should moisture or formation fluid come into contact with the CO_2. The entire injection tubing string will be comprised of 13Cr-L80 steel. Similarly, the 9.625-inch-long string casing will be constructed of 13Cr-L80 steel through the injection zone to above the confining zone. In areas where the risk of CO_2 corrosion is not a concern, J-55 mild steel will be utilized. Lithology of the storage reservoir's injection and confining zones are discussed in **Section *B.4*** and reservoir fluid characteristics are discussed in **Section *B.9***. The anticipated composition and temperature of the CO_2 stream, discussed in **Section *D.2*** and **Table 18**, is consistent with that of the U.S. CO_2-EOR industry, where mild steel is used. Constructing the wells with 13Cr steel components should exceed the protection requirements and be consistent with Guoqing Xiao (2020). The planned injection quantity is 1.25 Mt/y of CO_2 per well.

Stresses were analyzed and calculated according to worst-case scenarios, and casing specifications were selected accordingly. **Table 9** below summarizes the results of this analysis. The burst, collapse, and tensile strength of the casing were calculated according to the scenarios defined below and were dependent on fracture gradients, mud weight, depths, and minimum safety factors.

As demonstrated, the safety factors are sufficient in the worst-case scenarios to prevent migration of fluids into or out of USDWs or unauthorized zones (**Table 10**). The casing and tubing materials are designed to be compatible with the fluids encountered and the stresses induced throughout the sequestration project.

Table 9. Load Scenarios Evaluated

Load Name	Description	Casing String
Burst	The largest pressure differential occurs at either casing shoe or surface locations. The shoe scenario assumes formation fracture prior to casing rupture while the surface scenario assumes a gas kick while the wellbore contains drilling mud.	S
Collapse	For collapse consideration, the interior of the pipe is to be considered void and the consideration points are the casing shoe and the top of tail cement.	S
Burst	Cementing operation induces the largest rupture stresses, if lost circulation occurs during cementing, with all the tail cement in the pipe. The drilling fluid is used as a back-up.	P
Collapse	The greatest collapse stress occurs while cementing the casing, with an interior column of mud to counteract the external cement slurries.	P
Burst	The injection process induces the maximum pressure onto the injection tubing and, as such, represents the scenario of investigation.	T
Collapse	The design case for maximum loading occurs during annular pressure testing of the well, which assumes fluid inside the tubing is at a minimum specific gravity.	T
Tension	Tensile strength of the casing is governed by the entire weight of the string being analyzed while accounting for buoyancy effects.	S, P, T

S = surface casing; P = production or long-string casing; T = tubing

Table 10. Calculated Safety Factors for the Proposed Tubular Program

Tubular	Safety Factors		
	Burst (psia)	Collapse (psia)	Tension (lbs)
Surface (S)	3.82	1.61	7.76
Production (P)	1.54	1.82	2.40

C.3 Casing Summary

The injection well design will include the following casing strings: a 20-inch-diameter conductor casing string set at a depth of approximately 60 feet below ground surface (BGS) inside a 26-inch borehole; a 13.375-inch diameter surface casing string set at a depth of approximately 1,800 feet below ground surface (BGS) inside a 16-inch borehole; a 9.625-inch diameter long casing string set at a depth of approximately 11,400 feet BGS inside a 12.25-inch borehole; and a 6.625-inch diameter deep (injection) tubing string set at an approximate depth of 10,950 feet BGS. The 6.625-inch tubing will then crossover to a 5.5-inch diameter tubing string set to a depth of 11,360 feet BGS and be equipped with two sliding sleeves run in series, corresponding with the two injection zones. All casing strings will be cemented to the surface. The borehole diameters are considered conventional sizes for the sizes of casing that will be used and should allow ample clearance between the outside of the casing and the borehole wall to ensure that a continuous cement seal can be emplaced along the entire length of the casing string. **Table 11** summarizes the casing program for the injection well. **Table 12** summarizes properties of each casing material. Each section of the well is discussed in a separate section below.

Table 11. Borehole and Casing Program for the CO_2 Injection Well

Casing String	Casing Depth (Feet BGS)	Borehole Diameter (in.)	Casing Outside Diameter (in.)	Casing Material (weight/grade/ connection)	Coupling Outside Diameter (in.)
Conductor	60	26	20	94 lb/ft, Welded	21
Surface	0-1,800	16	13.375	54.5 lb/ft, J-55, STC	14.375
Long String	0-8,000	12.25	9.625	53.5 lb/ft, L-80, LTC	10.625
	8,000-11,400		9.625	53.5 lb/ft, CR13-L80, LTC	10.625

Table 12. Properties of Well-Casing Materials

Casing String	Casing Material (weight/grade/ connection)	Casing Outside/Inside/Drift Diameter (in.)	Burst (psia) Plain End	Collapse (psia)	Joint Tensile Strength (1,000 psia)
Conductor	94 lb/ft, Welded	20 / 19.124 / 18.936 (0.438 in wall)	2,110	520	907
Surface	54.5 lb/ft, J-55, STC	13.375 / 12.615 / 12.459 (0.38 in wall)	2,730	1,130	909
Long String	53.5 lb/ft, L-80, LTC	9.625 / 8.535 / 8.379 (0.545 in wall)	7,930	6,620	1,047
	53.5 lb/ft, CR13-L80, LTC	9.625 / 8.535 / 8.379 (0.545 in wall)	7,930	6,620	1,047
Tubing	28 lb/ft, CR13-L80, EUE	6.625 / 5.791 / 5.666 (0.417 in wall)	8,810	8,170	693
Tubing	23 lb/ft, CR13-L80, EUE	5.5 / 4.778 / 4.653 (0.4235 in wall)	9,190	8,830	503

C.3.1 Conductor Casing

The conductor casing consists of 20-inch diameter mild steel and provides the stable base required for drilling activities in unconsolidated sediment. Depending on wellsite conditions, this can be drilled and installed or driven directly. This section of casing is also cemented in place.

C.3.2 Surface Casing

The surface casing is 13.325-inch diameter 54.5-lb/ft J-55 pipe with short thread couplings (STCs). The metallurgy of this casing string is carbon steel. Surface casing is to be cemented to surface, isolating the USDWs through which the string extends. Following the cement setting, a bond log is run to ensure a sufficient seal to prevent the migration of fluid into USDWs.

C.3.3 Long-String Casing

The long-string casing will be 9.625-inch diameter pipe composed of two sections. The long-string casing is required to extend from the surface to the injection zone [40 CFR 146.86(b)(3)]. The uppermost section (approximately 8,000 feet) will be L-80 53.5-lb/ft carbon steel pipe with long thread couplings (LTCs); the lower section (8,000 to 11,400 feet) will be a corrosion-resistant alloy (e.g., 13Cr-L80 steel) having strength properties equivalent to or better than L-80 53.5-lb/ft pipe with LTCs. A DTS/DAS fiber optic cable will be run outside the casing from surface into the confining unit and cemented in place with the casing.

C.4 Tubing

The tubing connects the injection zone to the wellhead and provides a pathway for storing CO_2. This design utilizes 6.625-inch 28 lb/ft 13Cr-L80 steel, which resists corrosion from the injected fluid. At a depth of approximately 10,200 feet, a packer will be set to isolate injection zones from the tubing-casing annulus. At the end of the tubing string, a landing nipple, or "no-go" tool will be run. This will allow a plug to be set inside the tubing at this depth and the packer to be released in order to remove the tubing string if needed. Above the bottom packer, at approximately 10,950 feet, a 6.625-inch 28 lb/ft by 5.5-inch 20 lb/ft Crossover Connector will be run in the string to taper down the wellbore diameter to 5.5-inch 20 lb/ft 13Cr-L80 tubing. Across the injection zones, sliding sleeves will be utilized in the tubing string. These sleeves will enable two injection zones to be open or closed, independent of each other, to accommodate fluctuations in injection rates due to CO_2 availability. A packer will be placed between the sleeves at a depth of 11,075 feet to isolate injection into the Upper and Lower Paluxy. Tandem Pressure/Temperature gauges will be hung in the tubing string immediately above the top packer. Taking into account the anticipated formation pressure, temperature, and stress, the grade of tubing was selected with the API specifications outlined in **Table 13**, which includes the calculated safety factors. These safety factors represent sufficient quality standards to preserve the integrity of the injected fluid, the injection zone, and above USDWs. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid described in subsection C.5.1 below in accordance with 40 CFR 146.88(c).

Table 13. Calculated Safety Factors for the Proposed Injection Tubing

	Safety Factors		
Tubular	**Burst (psia)**	**Collapse (psia)**	**Tension (lbs)**
Tubing	2.75	1.22	2.28

C.5 Cementing Program

This section discusses the types and quantities of cement that will be used for each string of casing. The conductor, surface casing, and deep casing will be cemented to the surface in accordance with requirements at 40 CFR 146.86(b)(3). The proposed cement types and quantities for each casing string are summarized in **Table 14**.

Casing centralizers will be used on all casing strings to centralize the casing in the hole and help ensure that cement completely surrounds the casing along the entire length of pipe. The casing string will be centralized to attempt a minimum of 75% standoff. The actual hole trajectory will be input into the cementing service company's mud removal software to optimize centralizer placement. Centralizers will be placed either over the connections or at mid-joint using stop-rings as appropriate. It is estimated that approximately 150 or more centralizers will be used depending upon the hole trajectory.

Except for the conductor casing, a guide shoe or float shoe will be run on the bottom of the bottom joint of casing, and a float collar will be run on the top of the bottom joint of casing.

The long-string casing is to be cemented to the surface and will need to be completed in two stages. To facilitate a two-stage cement job, a multiple-stage cementing tool will be installed at an approximate depth of 5,000 feet. After the completion of the first-stage cement job, the multiple-stage cementing tool will be opened and fluid will be circulated down the casing and up the annulus above the cementing tool for a minimum of 8 hours to allow the first-stage cement job to acquire sufficient gel strength. The lower 3,400 feet (8,000 to 11,400 feet) of the 9.625-inch long-string casing will be cemented with "EverCRETE" (or similar) CO_2 corrosion-resistant cement. Cement-bond logs will be run and analyzed for each casing string.

Table 14. Cementing Program

Casing String	Casing Depth (ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (ft)	Cement
Conductor Casing	60	26	20	0-60 (cemented to surface)	Class A with 2% $CaCl_2$ (calcium chloride) and 0.25 lb/sack cell flake; cement weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 77 sacks.
Surface Casing	1,800	16	13.375	0-600 (cemented to surface)	Class A with 2% $CaCl_2$ and 0.25 lb/sack cell flake; weight: 15.6 lb/gal; yield: 1.20 ft^3/sack; quantity: 693 sacks.
Long Casing String – Stage 1	11,400	12.25	9.625	5,000-11,400	Lead-in: 65/35 Pozmix with 2% gel; weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 826 sacks. Tail: EverCRETE CO_2- resistant cement (or similar); weight: 15.92 lb/gal; yield: 1.08 ft^3/sack; quantity: 1,120 sacks.
Long Casing String – Stage 2				0-5,000 (cemented to surface)	65/35 Pozmix with 2% gel; weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 1485 sacks.

See acronym list for definition of abbreviations used in this table.

C.5.1 Annular Fluid

The annular space above the packer between the 9.625-inch long-string casing and the 6.625-inch injection tubing will be filled with fluid to provide a positive pressure differential to stabilize the injection tubing and inhibit corrosion. Annular fluid pressure at the surface will be controlled to remain between 250 psia and 500 psia during injection operations (See **Section *D.2.2.*** of the *Testing and Monitoring Plan* for a full description of the injection well annulus monitoring system. Added to the hydrostatic pressure of the fluid column, this will ensure that the annular pressure downhole will be greater than injection pressure.

The annular fluid will be fresh water treated with additives and inhibitors including a corrosion inhibitor, biocide (to prevent growth of harmful bacteria), and an oxygen scavenger. The fluid will be mixed onsite from good quality (clean) freshwater and liquid and dry additives, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The final choice of the type of fluid will depend on availability.

Example additives and inhibitors are listed below along with approximate mix rates:

- TETRAHib Plus (corrosion inhibitor for carbon steel tubulars [i.e., casings, tubing]) – 10 gal per 100 bbl of packer fluid
- CORSAF™ SF (corrosion inhibitor for use with 13Cr stainless steel tubulars or a combination of stainless steel and carbon steel tubulars) – 20 gal per 100 bbl of packer fluid
- Spec-cide 50 (biocide) – 1 gal per 100 bbl of packer fluid
- Oxban-HB (non-sulfite oxygen scavenger) – 10 gal per 100 bbl of packer fluid.

These products were recommended and provided by Tetra Technologies, Inc., of Houston, Texas. Actual products may vary from those described above.

C.5.2 Wellhead

The wellhead will consist of the following components, from bottom to top:

- 20.75-inch x 13.375-inch, 3,000-psia casing head

- 13.625-inch fiber optic line port/access
- 13.625-inch x 9.625-inch, 5,000-psia casing head
- 11-inch x 7.0625-inch, 5,000-psia tubing head
- 7.0625-inch 5,000-psia full-open master control gate valve
- 7.0625-inch 5,000-psia automated tubing flow control valve
- 7.0625-inch 5,000-psia cross with one (1) 7.0625-inch, 5,000-psia blind flange
- 7.0625-inch 5,000-psia automated tubing flow control valve
- 7.0625-inch x 2.875-inch, 5,000-psia top flange and pressure gauge.

The wellhead and Christmas tree will be composed of materials that are designed to be compatible with the injection fluid. Critical components that come into contact with the CO_2 injection fluid will be made of a corrosion-resistant alloy such as stainless steel. Materials that are not expected to contact the injection fluid, such as the surface casing and shallow portion of the long-string casing, will be manufactured of carbon steel. A preliminary materials specification for the wellhead and Christmas tree assembly is described in **Table 15**, using material classes as defined in American Petroleum Institute (API) Specification 6A (Specification for Wellhead and Christmas Tree Equipment). A summary of material class definitions is provided in **Table 16**. The final wellhead and Christmas tree materials specification may vary slightly from the information given below because neither has been selected yet. An illustration of the wellhead and Christmas tree is provided in **Figure 49.** The flow line leading to the wellhead and Christmas tree will be equipped with an automatic shutoff valve as required in section 146.88.

Table 15. Materials Specification of Wellhead and Christmas Tree

Component		Material Class[a]
Casing Head Housing (for 20-in. surface casing)		DD, EE
Casing Head Spool (for 13-3/8-in. intermediate casing	Casing spool (20-3/4 in. 3K X 13-5/8 5K)	AA, BB, DD, EE
	Casing hanger (20 in. X 13-3/8 in.)	AA, DD
Tubing Spool Assembly (for 9-5/8-in. long-string casing)	Spool	AA
	Casing hanger	AA, DD
Christmas Tree	Tubing head adapter	DD, EE
	Manual gate valve	BB
	Pneumatic actuated gate valves (2)	BB
	Tubing hangar (for 6-5/8-in. tubing)	CC

(a) When multiple classes are given, the highest class applies. Vault uses this convention because not all components are available in all class types.

Table 16. Material Classes from API 6A (Specification for Wellhead and Christmas Tree Equipment)

API Material Class	Body, Bonnet, End & Outlet Connections	Pressure Controlling Parts, Stems, & Mandrel Hangers
AA – General Service	Carbon or alloy steel	Carbon or low-alloy steel
BB – General Service	Carbon or low-alloy steel	Stainless steel
CC – General Service	Stainless steel	Stainless steel
DD – Sour Service[a]	Carbon or low-alloy steel[b]	Carbon or low-alloy steel[b]
EE – Sour Service[a]	Carbon or low-alloy steel[b]	Stainless steel[b]
FF – Sour Service[a]	Stainless steel[b]	Stainless steel[b]
HH – Sour Service[a]	Corrosion-resistant alloy[b]	Corrosion-resistant alloy[b]

Source: Cameron Surface Systems, Houston, Texas

(a) As defined by National Association of Corrosion Engineers (NACE) Standard MR075.

(b) In compliance with NACE Standard MR0175.

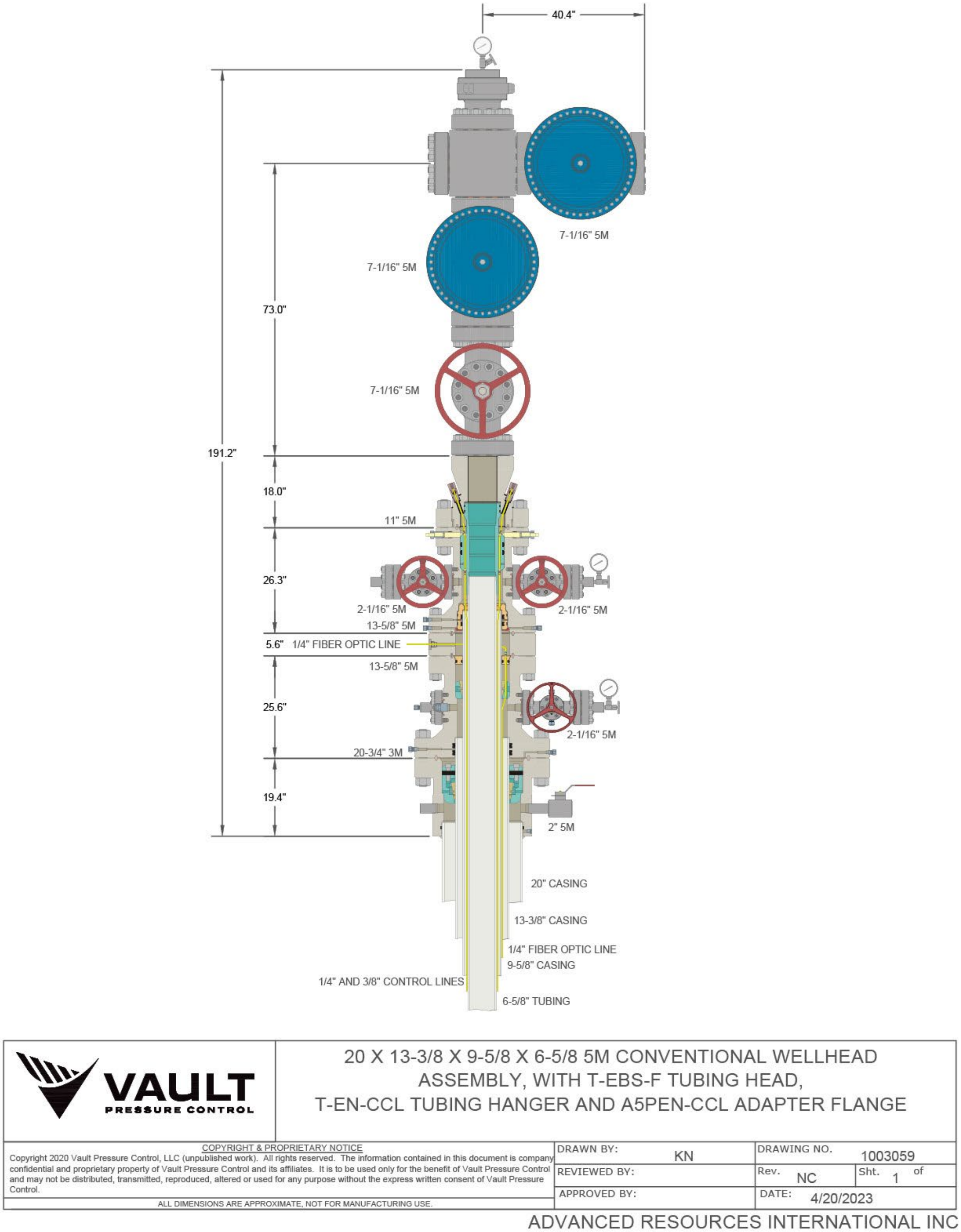


Figure 49. Illustration of the Wellhead and Christmas Tree

C.5.3 Perforations

The long-string casing will be perforated across the Paluxy Sandstone with deep-penetrating shaped charges. The exact perforation interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. The planned perforation intervals will be set between 10,269 feet and 11,347 feet with 6 shots-per-foot and 60-degree phasing. Proposed perforation interval depths are found below in **Table 17**.

Table 17. Proposed Perforated Intervals

Perforated Zones	Perforated Interval	Top (ft)	Bottom (ft)	Mid-Point (ft)
Upper Paluxy	1	10,269	10,318	10,294
	2	10,351	10,400	10,376
	3	10,433	10,743	10,588
	4	10,809	10,956	10,883
Lower Paluxy	5	11,191	11,217	11,204
	6	11,295	11,347	11,321

C.5.4 Schematic of the Subsurface Construction Details of the Well

A schematic of the Injection Well LL#1 is shown in **Figure 50**. **Figure 51** shows the detail of the perforations, sliding sleeves, gauges, and tubing string packers. A schematic of Injection Wells LL#2, LL#3, and LL#4 is shown in **Figure 52.**

As discussed in the previous sections, the injection well(s) will include the following casing strings: a 20-inch diameter conductor string set at a depth of approximately 60 feet BGS; a 13.325-inch diameter surface string set at a depth of approximately 1,800 feet BGS; and a 9.625-inch diameter deep string set at an approximate depth of 11,400 feet BGS. All depths are preliminary and will be adjusted based on additional characterization data obtained while drilling the CO_2 injection wells. At minimum, the conductor, surface, and long casing strings will be cemented to surface.

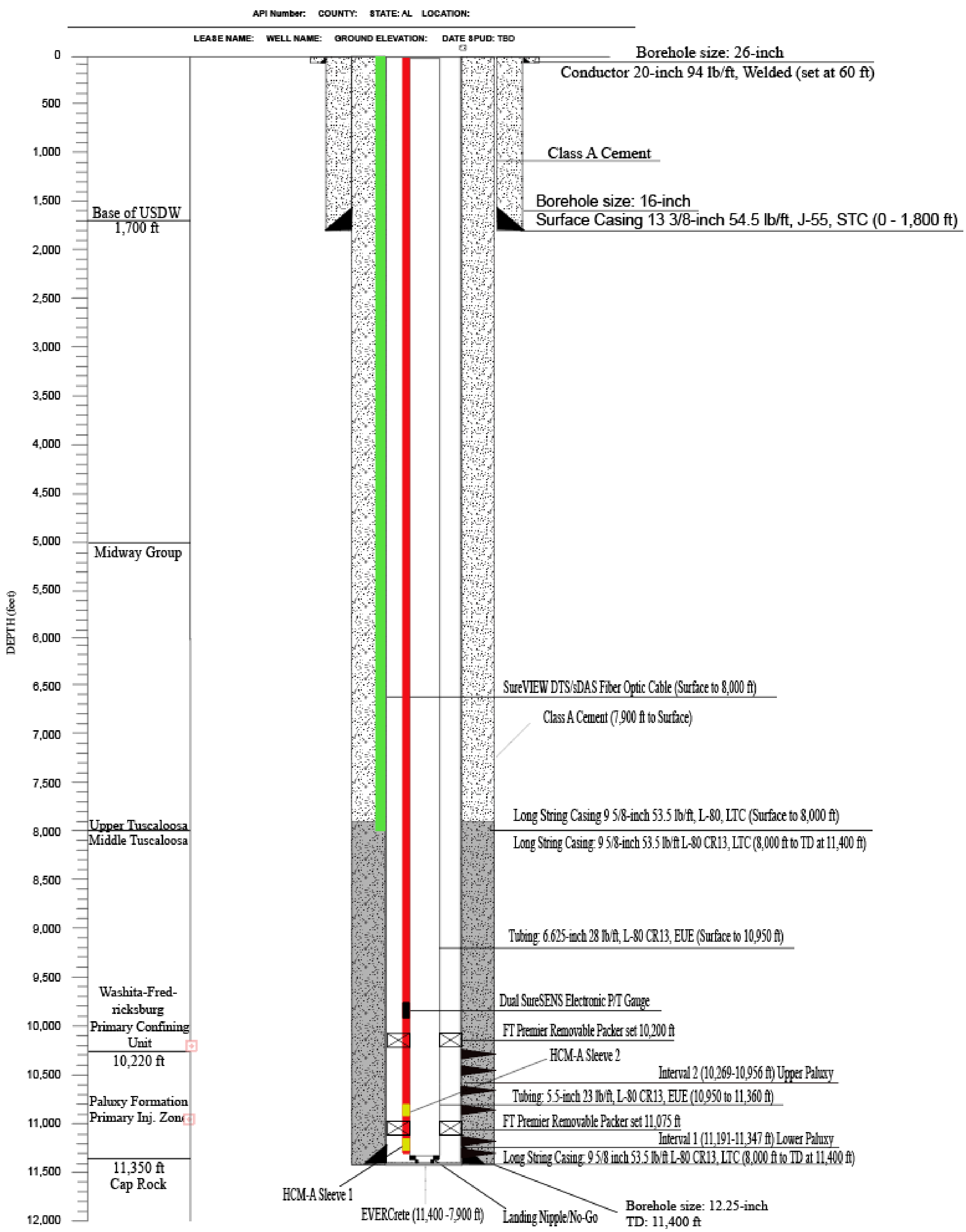


Figure 50. Injection Well Schematic

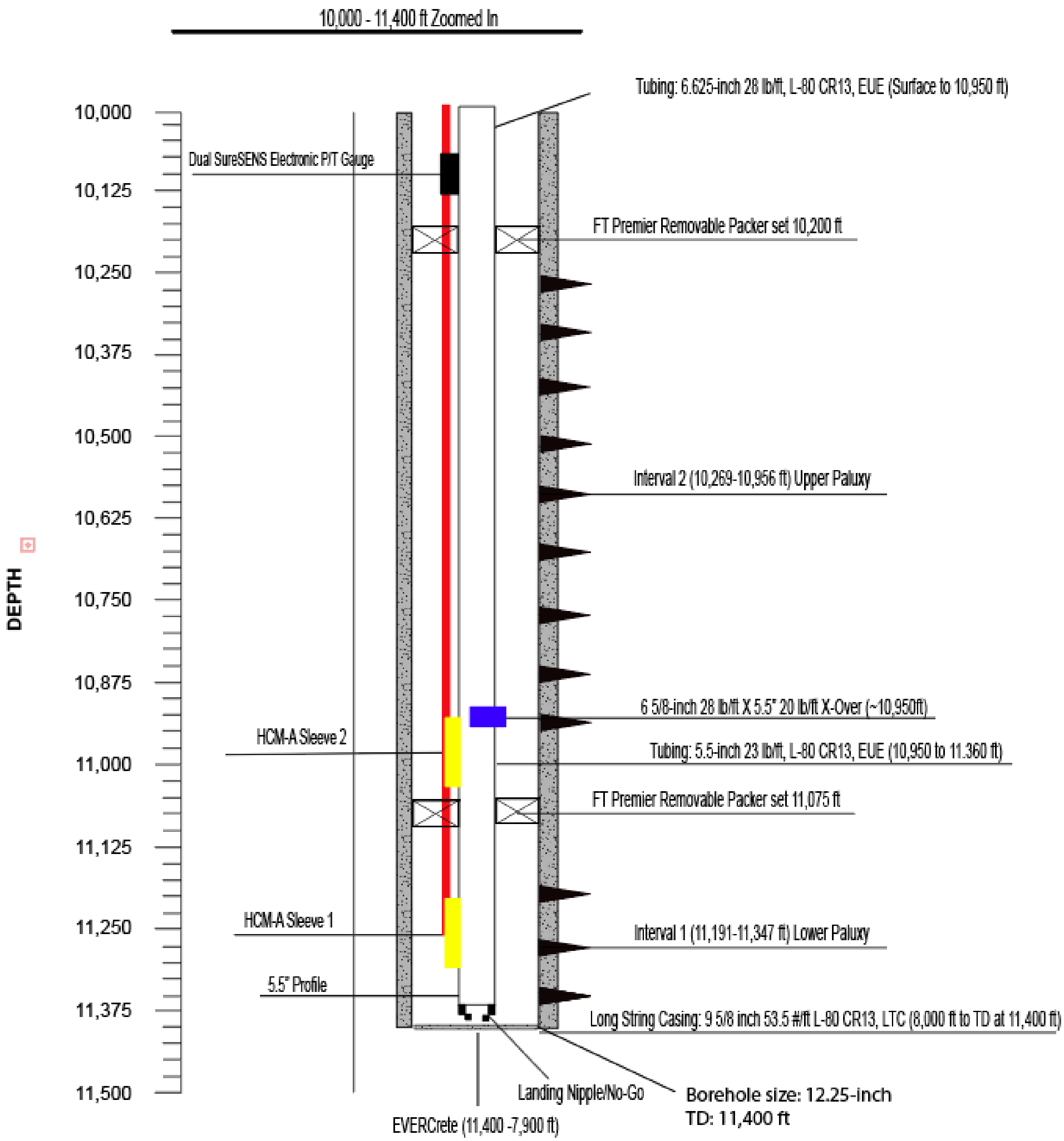


Figure 51. Injection Well Schematic (Zoomed 10,000-11,400 ft.)

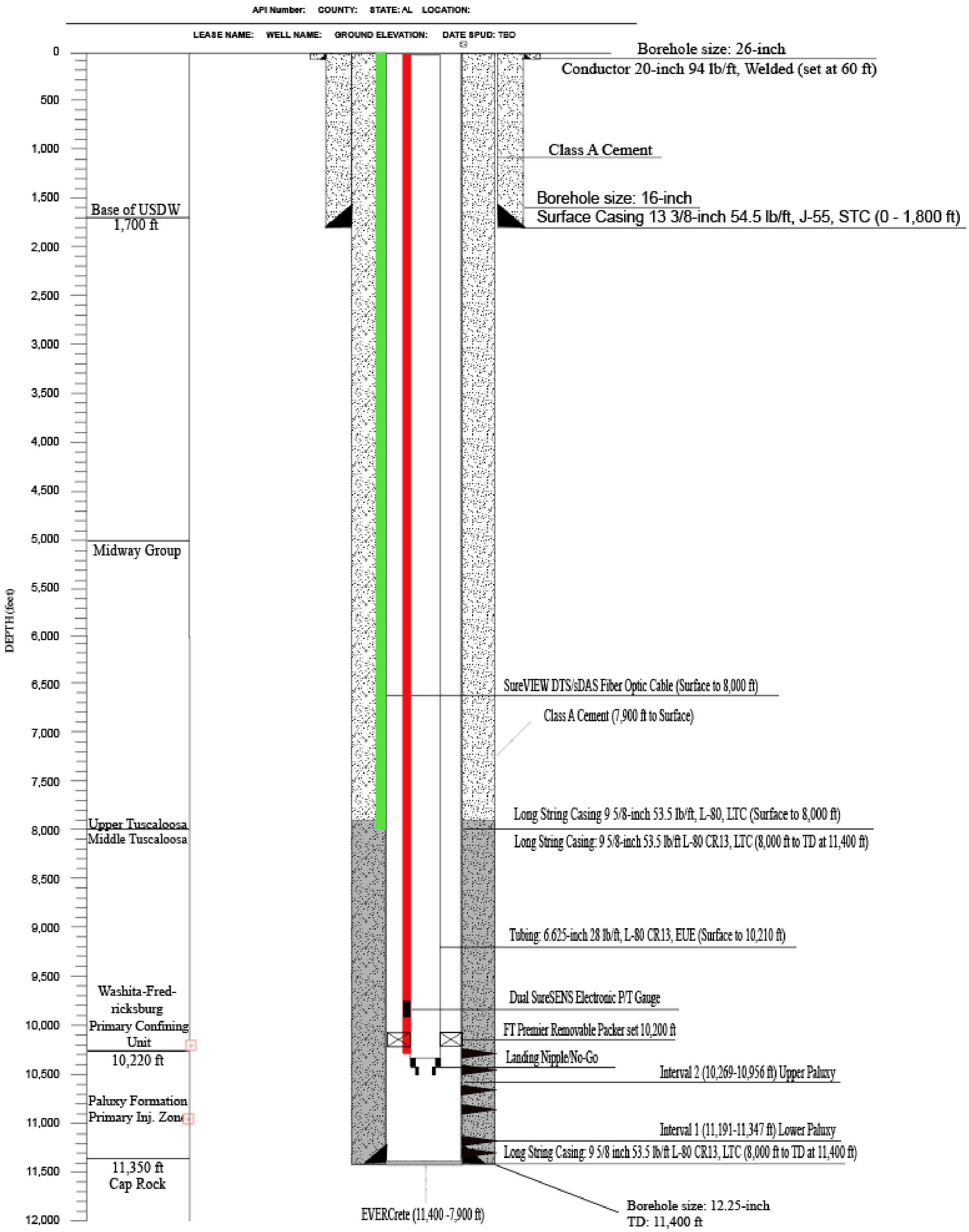


Figure 52. LL #2, #3, and #4 Injection Well Schematic (No Sleeves)

D. INJECTION WELL OPERATIONS PLAN

D.1 Introduction

By following the injection well operations program for the Longleaf CCS Hub described in this Plan, Longleaf CCS, LLC seeks to safely inject an average rate of 3,425 mt/d per well (65,000 MMcf/day) of CO_2 into the Paluxy reservoir at four injection wells, LL#1, LL#2, LL#3, and LL#4, while avoiding geomechanical effects and maintaining well integrity. At full operations, the four injection wells will be injecting up to 13,700 mt/d (260 MMcf/day) into the Paluxy reservoir (see **Figure 3** for well locations). The operational details provided in this document satisfy 40 CFR 146.82(a)(7) and (10). The operational design described in this document has been developed to adhere to requirements set forth in 40 CFR 146.88.

D.2 Specifications of the CO_2 Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

The CO_2 injection stream will enter the storage site meeting the anticipated specifications presented in **Table 18**. The CO_2 will be sourced from a series of industrial and power plants located in the Mobile, Alabama area and transported by pipeline to the Longleaf CCS Hub. The CO_2 will enter a distribution header and be piped to each injection wellhead. The CO_2 will be in the liquid phase as it enters the wellhead and will transition to a supercritical phase in the wellbore.

Table 18 displays the chemical composition of the anticipated CO_2 stream.

Table 18. Specifications of the Anticipated CO_2 Stream Composition

Component	Specification	Unit
Minimum CO_2	>96	mole%, dry basis
Water content	<20	lb/MMscf
Impurities (dry basis):		
Total Hydrocarbons	<2	mol%
Inert Gases (N_2, Ar, O_2)	<4	mol%
Hydrogen	<1	mol%
Alcohols, aldehydes, esters	<500	ppmv
Hydrogen Sulfide	<100	ppmv
Total Sulfur	<100	ppmv
Oxygen	<100	ppmv
Carbon monoxide	<100	ppmv
Glycol	<1	ppmv

On average, the CO_2 stream will be 75 ºF and approximately 1,500 psi in the pipeline, with an estimated density of 51.93lb/ft^3 at wellhead conditions. After injection into the Paluxy Formation, the CO_2 stream is anticipated to heat to near formation temperature of approximately 240 ºF at or above the native reservoir pressure of approximately 5,000 psi, with an estimated density of 40.9 lb/ft^3, in a supercritical state[2].

Due to the anticipated low water content within the CO_2 stream, CO_2-induced corrosion affecting well components is not likely - as noted by the U.S. EPA well construction guidance (US EPA, 2012). Longleaf CCS, LLC will, however, monitor for potential corrosion induced by the injectate as outlined in Section C of the *Testing and Monitoring Plan*.

D.3 Operational Procedures [40 CFR 146.82(a)(10)]

The operational procedures described here were developed to factor in the thermohydraulic performance of the four injection wells based on wellbore design parameters described in section C of this *Application Narrative*. The analysis of the design parameters and ensuing calculations are also described in this section C of this *Application Narrative.*

D.3.1 Operational Conditions

Longleaf CCS, LLC plans to inject 1.25 Mt/y (3,425 mt/d) of CO_2 at each of four injection wells. As described in Section C.3 of this *Application Narrative*, injection well LL#1 will be equipped with a series of sliding sleeves across the Upper and Lower Paluxy Formation to prevent the injection stream from flashing in a low injection volume scenario. Injection wells LL#2, LL#3, and LL#4 likely will not have sliding sleeves installed. To confirm that this annual injection rate of 1.25 Mt/y can be achieved with the proposed well design, as well as the proposed maximum instantaneous injection rate of 1.50 Mt/y (4,110 mt/d), operational conditions for both well construction types and both injection rates were modeled using SLB *PIPESIM* software, a steady-state multi-phase flow simulator.

Calculations in *PIPESIM* consider the pressure-volume-temperature (PVT) properties of CO_2 flowing through a 6 5/8-inch tubing with sliding sleeves as well as a 6 5/8-inch tubing without sliding sleeves to a bottomhole depth of 11,347 ft. Pressure along the wellbore tubulars was modeled using surface roughness (friction), hydrostatic effects, and fluid velocity. **Table 19** summarizes the operational inputs for the SLB *PIPESIM* analysis. The injection wells will be continually monitored for injection pressure, rate, volume, temperature of the CO_2 stream, and

[2] https://webbook.nist.gov/chemistry/form-ser/

tubing-long string casing annulus pressure and fluid volume. The continuous monitoring program for pressure and injection rates is included in Section D of the *Testing and Monitoring Plan*. Injection will occur through the injection tubing string and never between the outermost casing protecting USDWs and the tubing (40 CFR 146.88(b)).

Table 19. Inputs to Wellbore Calculations in SLB *PIPESIM*

Input Parameter	Value	Unit
Injection Zone Permeability	31 - 233	mD
Wellhead Temperature	90	°F
Injection Zone Temperature	235 - 252	°F
Damaged Permeability Ratio	1	n/a
Skin Permeability Ratio	1	n/a
Paluxy Top Depth	10,220	ft
Paluxy Bottom Depth	11,347	ft
Injection Zone Top Depth	10,269	ft
Injection Zone Bottom Depth	11,347	ft
CO_2 Purity	>96	%
Perforations (60-degree phase)	6	Shots per Foot
Pressure Gradient	0.463	psi per ft
Temperature Gradient	1.65	°F per 100 ft

PIPESIM analysis of an injection rate of 1.25 Mt/y in a well that has been constructed without a sliding sleeve resulted in a wellhead pressure of 1,491 psia, shown in **Figure 53**. At the maximum instantaneous injection rate of 1.50 Mt/y, the resulting wellhead pressure is expected to be 1,534 psia, shown in **Figure 54**.

In injection well LL#1 with sliding sleeves, an injection rate of 1.25 Mt/y, and the lower perforations closed and upper perforations open, the *PIPESIM* analysis resulted in a wellhead pressure of 1,500 psia, shown in **Figure 55**. Additional SLB *PIPESIM* nodal analysis inputs and results can be found in Section D.5. of this *Application Narrative.*

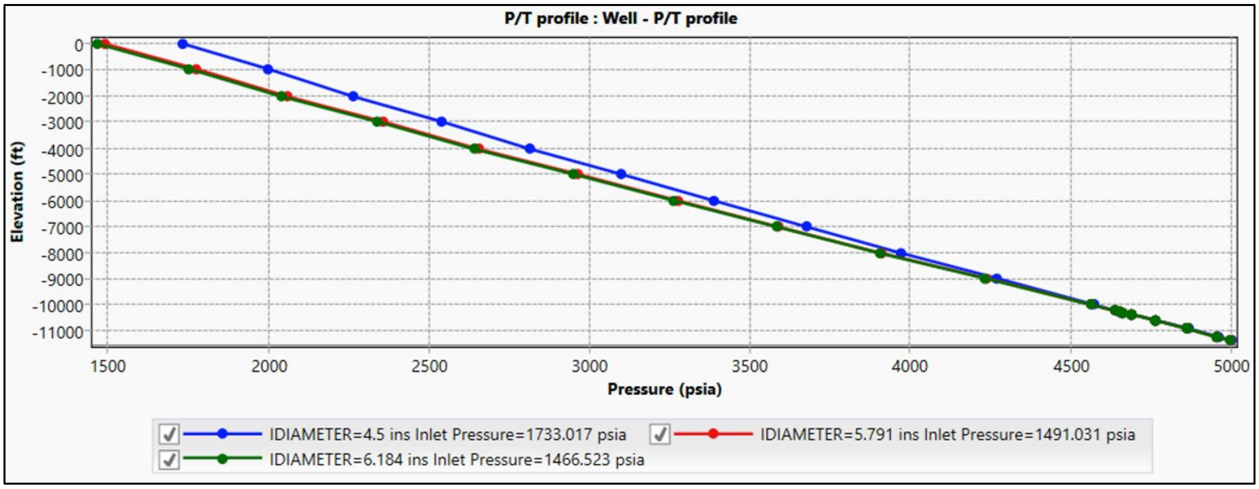


Figure 53. Pressure Profile of a Well Without Sliding Sleeves at an Injection Rate of 1.25 Mt/y

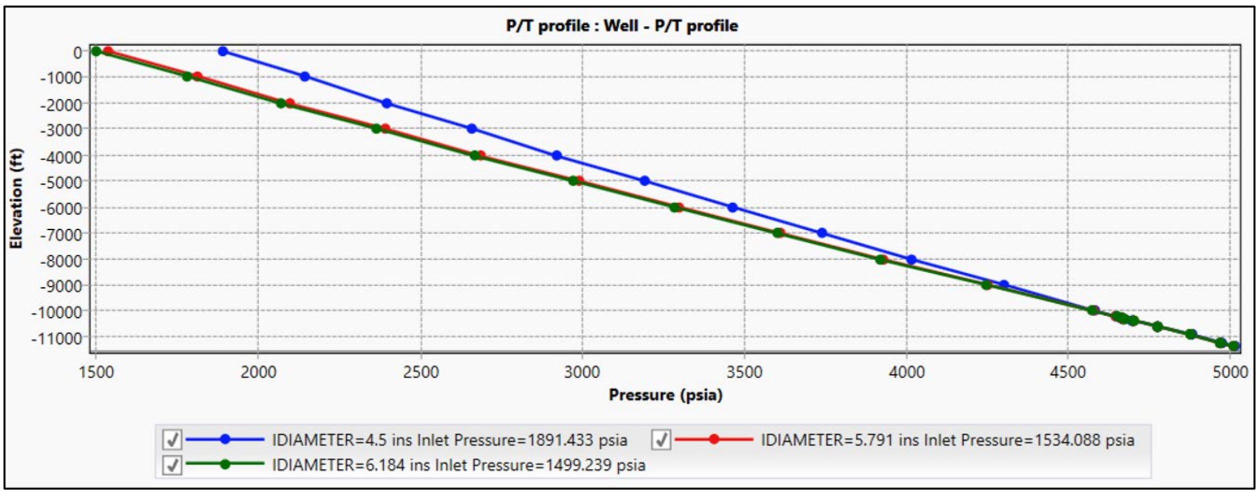


Figure 54. Pressure Profile of a Well Without Sliding Sleeves at an Injection Rate of 1.50 Mt/y

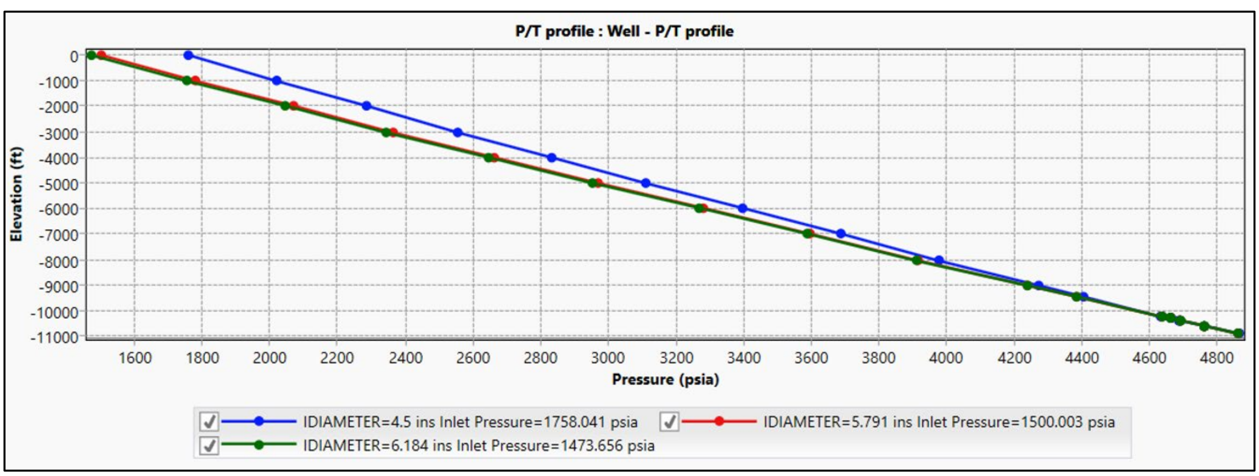


Figure 55. Pressure Profile of a Well with Sliding Sleeves at an Injection Rate of 1.25 Mt/y

The estimated hydraulic fracture gradient and the hydraulic fracture pressure at the injection zone top-depth in the *PIPESIM* model is 7,188 psi (0.7 psi/ft * 10,269 ft), corresponding to a maximum bottomhole pressure of 6,469 psi, as required by 40 CFR 146.88(a) to not exceed 90% of the fracture pressure of the injection zone. See **Table 21** for well specific bottomhole injection pressure limits. The modeled bottomhole pressure and the increased reservoir pressure during injection (See Section A.3.d of the *Area of Review and Corrective Action Plan*) for all injection rates was considerably less than 90% of the fracture pressure of the reservoir.

Injection tubing will be deployed and set via a packer placed above the perforations. The injection wells will be monitored for potential annular leaks and external mechanical integrity as outlined in Section D of the *Testing and Monitoring Plan*. The annular space between the long-string casing and the injection tubing will be filled with a corrosion inhibitor as described in Section C.5.1 of this Application Narrative.

The annular pressure between the tubing and the casing downhole will be maintained at a pressure higher than the injection pressure during injection to satisfy requirements in 40 CFR 146.88(c). Annular pressure may be reduced during periods of well workover (maintenance) approved by the UIC Program Director in which the sealed tubing/casing annulus is disassembled for maintenance or corrective procedures.

D.3.2 Injection Start-Up

Longleaf CCS. LLC will ramp up injection operations as detailed in **Table 20** and conduct operational monitoring of the injection site pursuant to 40 CFR 146.90(b). Specific details of the startup protocol are outlined below.

A multi-stage startup procedure will be implemented in conjunction with data acquired from surface and downhole pressure and temperature gauges in all injection wells, as well as in-zone and above-zone monitoring wells.

During the start-up period Longleaf CCS, LLC will collect daily operational data and include these data in semi-annual reports as required by 40 CFR 146.91(a) and described in Section K.1 of the *Testing and Monitoring Plan*. At the UIC Program Director's request, Longleaf CCS, LLC will schedule a conference call to discuss the operational data during the start-up.

A series of successively higher injection rates will be used during injection start-up (an example start-up operational procedure is shown in **Table 20** and may be modified to accommodate the available volume of CO_2 at the start of injection), with the elapsed time and pressure values recorded for each rate and time step. Each rate step will last approximately 24 hours. At no point during the procedure will the injection pressure exceed the maximum permitted bottomhole injection pressure which is 90% of the top Paluxy Formation injection interval depth fracture pressure (see Section D.3.1 above). If requested by the UIC Program Director, Longleaf CCS, LLC will provide the final start-up operational procedure.

Table 20. Example Operational Procedure During Start-Up

Rate (mt/d)	Duration (Hours)	Precent of Maximum Injection Rate (%)
572	24	16.7
1,142	24	33.3
1,712	24	50
2,284	24	66.7
2,853	24	83.3

Injection rates will be measured (using a Coriolis flow meter) and data will be continuously recorded. Surface and downhole pressure and temperature data will be collected continuously in the injection and monitoring wells. During the start-up period, a plot of injection rate and the corresponding stabilized pressure values will be graphically represented to demonstrate that well integrity has been maintained.

During the start-up period, the project team will look for any evidence of anomalous pressure behavior. If anomalous pressure behavior is observed, the project team will conduct additional monitoring to better characterize the anomaly. If during the start-up period the project team determines that anomalous pressure behavior indicates a downhole pressure that could lead to formation fracturing, injection will be stopped, and the line valve closed allowing the pressure to bleed-off into the injection zone. The instantaneous shut-in pressure (ISIP) will be measured, and the pressure data will be reviewed for event signatures. In this event, Longleaf CCS, LLC will notify the UIC Program Director within 24 hours of the root cause determination. Longleaf CCS, LLC will consult with the UIC Program Director before initiating further injection.

D.4 Injection Rates

The injection wells will be constructed as shown in Section C of this *Project Narrative*. Injection will be facilitated through injection tubing set in the long casing string by a packer above the topmost perforations in the Paluxy Formation. **Table 21** summarizes the proposed operational parameters for all injection wells. Operational parameters are expected to remain constant throughout the duration of the injection period. Some variability to operational parameters may stem from variations in volume from a CO_2 source, which may lead to lower injection volumes during limited periods of time. The injection rate values detailed in **Table 21** were modeled in *PIPESIM*, and the nodal analysis results can be found in Section C.1 of this *Application Narrative.*

Table 21. Injection Well Operational Parameters

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
At Wellhead (All Injection Wells)	2,220	psia
Downhole – LL #1 (Paluxy Top injection depth of 10,270 ft TVD GL)	6,470	psia
Downhole – LL #2 (Paluxy Top injection depth of 10,340 ft TVD GL)	6,514	psia
Downhole – LL #3 (Paluxy Top injection depth of 10,270 ft TVD GL)	6,470	psia
Downhole – LL #4 (Paluxy Top injection depth of 10,168 ft TVD GL)	6,405	psia
Injection Rates		
Maximum Instantaneous Injection Rate (CO_2) (One Injection Well)	4,110	mt/d
Maximum Instantaneous Injection Rate (CO_2) (One Injection Well)	1.50	Mt/y
Average Injection Rate (CO_2) (One Injection Well)	3,425	mt/d
Average Injection Rate (CO_2) (One Injection Well)	1.25	Mt/y
Maximum Annual Injection (CO_2) (One Injection Well)	1.25	Mt
Maximum Annual Injection (CO_2) (Four Injection Wells)	5.0	Mt
Total Injection Mass (30-year period) (One Injection Well)	37.5	Mt
Total Injection Mass (30-year period) (Four Injection Wells)	150	Mt
Annular Pressure		
Maximum Annulus Surface Pressure (All Injection Wells)	500	psia
Minimum Annulus Pressure at the Wellhead (All Injection Wells)	250	psia

Using a per well average annual CO_2 injection rate of 1.25 Mt/y (3,425 mt/d) and a maximum instantaneous rate of 1.5 Mt/y (4,110 mt/d), the injection tubing string size was selected to meet project requirements. The expected wellhead pressure during injection operations will likely be between 1,200 psia and 1,500 psia but may be as high as 2,220 psia during maximum instantaneous injection periods. At a wellhead pressure of 1,534 psia and a maximum instantaneous rate of 4,110 mt/d, bottomhole pressures are still considerably less than the maximum allowable downhole pressure for all injection wells.

Based on expected operating ranges, the Project proposes to maintain annular pressure at the surface between 250 to 500 psia. Because of the lower CO_2 density in the injection tubing string, this should result in bottomhole conditions whereby the annular fluid is at a higher pressure than that within the injection tubing string. Final design criteria will be developed for the permission to operate the injection well.

D.5 Estimated Maximum Allowable Surface Pressure

In *PIPESIM,* the maximum allowable wellhead pressure observed during simulation of injection in a well with sliding sleeves and a bottomhole pressure of 6,484 psia (90% fracture pressure at a depth of 10,294 ft) was 2,664 psia, **Figure 56**. When injection was modeled using a maximum instantaneous rate of 1.5 Mt/y (4,110 mt/d), the resulting wellhead pressure was 1,534 psia. The maximum allowable surface pressure (MASP) for all injection wells will be 2,220 psia, well below the modeled wellhead pressure of 2,664 psia that corresponds with bottomhole pressures near 90% of fracture pressure. Operating wellhead pressures will likely range from 1,200-2,220 psia.

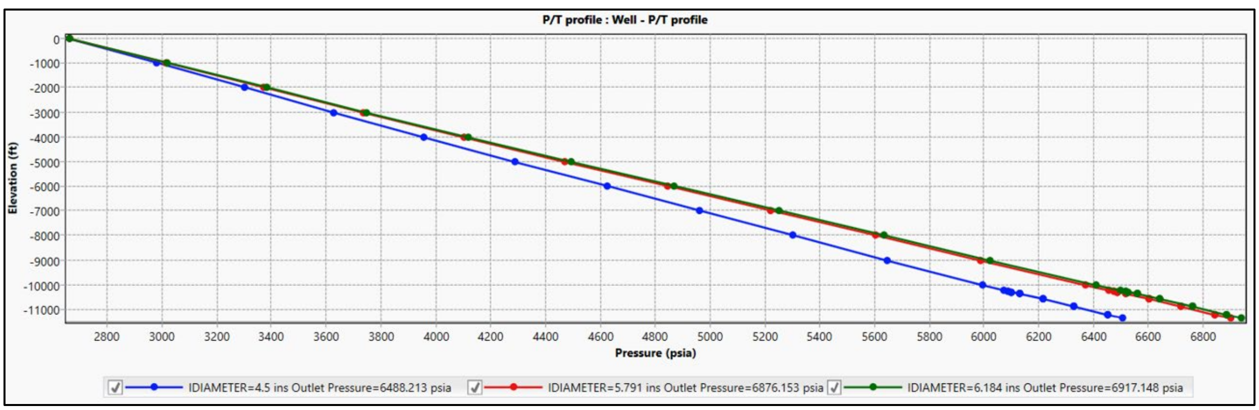


Figure 56. Pressure Versus Depth Profile at 90% of Fracture Pressure at the Top of the Paluxy Formation.

D.6 Injection Well Operational Monitoring

Each injection well will be monitored to ensure safe operations, in compliance with 40 CFR 146.88(e)(2). Operational safety monitoring includes continuous monitoring of the injection pressure at the wellhead and bottomhole, continuous monitoring the pressurized annulus, continuous fiber optic temperature monitoring along the well, and corrosion coupon monitoring to identify corrosion. Each of these monitoring systems is fully described in the *Testing and Monitoring Plan.*

Each injection well will have a wellhead pressure gauge (tubing and annular pressure) and flow computer, both tied into the injection control system and set to trigger an alarm at the project control room and shut down injection in the well if: (1) the MASP is reached; (2) the CO_2 injection rate exceeds maximum permitted rate; or (3) the annulus fluid pressure drops below the injection pressure. Injection parameters, including pressure, rate, volume and/or mass, and temperature of the CO_2 stream, will be continuously measured and recorded. The pressure and fluid volume of the annulus between the tubing and long-string casing will also be continuously recorded.

All automatic shutdowns will be investigated prior to bringing injection back online to ensure that no integrity issues were the cause of the shutdown. If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered, Longleaf CCS, LLC will immediately investigate and identify, as expeditiously as possible, the cause of the shutdown. Please refer to Appendix A of the *Emergency and Remedial Response Plan (ERRP)* for response actions if mechanical integrity is lost.

The annular space between the tubing and long string casing of each injection well will be pressurized with corrosion inhibiting brine and monitored for changes in pressure and volume. The fiber optic cable cemented onto the outside of the long-string casing will be used to continuously monitor temperature along the length of the casing through the primary confining unit, the Tuscaloosa Marine Shale. Rapid temperature changes or other excursions from a normal operating temperature profile will be investigated to ensure that there has been no breach of wellbore integrity.

D.7 Workover and Maintenance

Longleaf CCS, LLC will monitor and maintain mechanical integrity of each injection well at all times. Well maintenance and workovers will be part of normal operations to keep each injection well in a safe operating condition. Procedures for well maintenance will vary depending on the nature of the procedure. All maintenance and workover operations will be monitored to ensure there is not a loss of mechanical integrity. Barriers, such as a downhole plug, will be placed to ensure leakage risk is minimized. As outlined in Section K of the *Testing and Monitoring Plan*, Longleaf CCS, LLC will notify the UIC Program Director of any planned workover or injection well test at least 30 days in advance, and the results of any mechanical integrity test, workover, or injection well test will be provided within 30 days after the test or maintenance is completed (40 CFR 146.91).

Each injection well is designed to allow the installation of a temporary plug below the tubing to allow the tubing to be removed and replaced as needed while keeping a barrier in place. The bottomhole temperature and pressure gauge is set above the packer to allow for replacement, if needed, without removing the packer from the well.

E. SUMMARY OF OTHER PLANS

E.1 AOR and Corrective Action Plan

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

The information and files submitted in the *Area of Review and Corrective Action Plan* satisfy the requirements of **40 CFR 146.84(b).** This plan addresses how the Area of Review (AoR) will be delineated and uses corrective action techniques to address all deficient artificial penetrations and other features that compromise the integrity of the confining zone above the injection zone. The AoR encompasses the entire region surrounding the Longleaf CCS Hub where USDWs may be endangered by injection activity. The AoR is delineated by the lateral and vertical migration extent of the CO_2 plume, formation fluids, and pressure front in the subsurface. A computational model was built to model the subsurface injection of CO_2 into the Paluxy Formation in the Longleaf CCS Hub. The *GEM* simulator is used to assess the development of the CO_2 plume, the pressure front, and the long-term fate of the injection. The AoR is delineated by the full lateral and vertical extent of the CO_2 plume in the subsurface and used to monitor where USDWs may be compromised by injection activity. This plan details the computational modelling, assumptions that are made, and site characterization data that the model is based on to satisfy the requirements of **40 CFR 146.84(c).**

Per **40 CFR 146.82(a)(4)**, wells that penetrate the injection or confining zone within the AoR must be tabulated. There are no existing wellbores that penetrate the primary confining unit within the AoR. In Section B.2 of the *AoR and Corrective Action Plan* is a listing of the nearest wellbores to the AoR and information that these wells have been plugged and abandoned in compliance with Alabama Oil and Gas Board (AOGB) requirements.

E.2 Financial Responsibility

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

The *Financial Responsibility Plan* demonstrates the financial responsibility for injection well plugging/conversion, Post-Injection Site Care (PISC), site closure, and emergency and remedial response according to requirements of **40 CFR 146.85**. As mentioned earlier, no corrective action is anticipated at the Longleaf CCS Hub as there are no penetrations into the confinement interval currently. The *Financial Responsibility Plan* includes financial instruments to cover the costs of one (1) emergency leakage event as discussed in the ***ERRP***. The *Financial Responsibility Plan* includes financial instruments to cover the costs of well plugging as discussed in the ***Injection Well Plugging Plan***. The *Financial Responsibility Plan* also includes financial instruments that cover the costs of 20 year of post-injection site care and site closure as discussed in the ***Posts-Injection Site Care (PISC) and Site Closure Plan***. For more details, refer directly to the *Financial Responsibility Plan* where the financial instrument(s) are outlined and costs are presented in more detail.

E.3 Pre-Operational Testing Plan

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

The ***Pre-Operational Testing Plan*** is designed to establish an accurate baseline dataset of pre-injection site conditions, verify depths and physical characteristics of geologic formations germane to the injection and confining zones, and ensure that injection well construction satisfies requirements outlined in **40 CFR 146.86**.

During the drilling and construction phase of the project, appropriate log suites, surveys, and tests will be deployed to verify the depth, thickness, porosity, permeability, and lithology of pertinent geologic formations, as well as the salinity of formation fluids within them. Deviation checks will be performed during drilling at frequent intervals to keep track of the borehole location in the subsurface and serve as a reference for steering purposes to achieve as near to vertical wellbore as possible. These checks will also assist in assuring that avenues for vertical fluid movement are not created in the form of diverging holes while drilling. Mudlogs will be acquired throughout the drilling process. When the well reaches 1,800 ft., resistivity, spontaneous potential, and caliper logs will be run before surface casing is run. A cement bond log will be run to evaluate radial cement quality once the casing is cemented in place.

Once the well is drilled to total depth (TD), resistivity and spontaneous potential logs, porosity, caliper, gamma ray, NMR, sonic, and formation micro imager logs will be run prior to the installation of the long string casing. Cement bond, variable density, and temperature logs will be run after long string casing is cemented in place to verify the quality of the cement job. Internal and external mechanical integrity of the injection wells will be tested to demonstrate the absence of leaks in the wellbore that could result in migration of CO_2 out of the injection zone. An annular pressure test will be performed within 24 hours of cementing casing.

Core samples will be taken from the confining and injection zones while drilling the first observation well, IOB#1. Analysis of these cores will be correlated to analysis of well logs as part of the pre-operational geologic site characterization updates. Fluid samples will be collected from the injection zone in the proposed injection wells to establish baseline measurements for fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone. Fracture pressure will be determined using the formation testing tool and minifrac tests in IOB#1. Fracture pressure tests will not be conducted in the injection wells to prevent borehole rugosity and washouts and ensure mechanically sound cement jobs.

Upon completion and before operation, hydrogeologic characteristics of the injection zone will be determined by performing a composite injectivity evaluation test in the injection interval to determine the large-scale transmissivity through the reservoir. Reports detailing the results and interpretations of all testing operations will be provided to the EPA following conclusion of analysis.

E.4 Testing and Monitoring Plan

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

The *Testing and Monitoring Plan* is designed to ensure that injection and storage of CO_2 at the Longleaf CCS Hub is done safely, without endangerment to local USDWs or communities, and satisfies the requirements under **40 CFR 146.90**. A *Quality Assurance and Surveillance Plan* is attached as an Appendix to the *Testing and Monitoring Plan*.

Data collected during the implementation of this Plan will be used to confirm that injection procedures are operating as planned, that USDWs are protected, and that the CO_2 plume and pressure front are developing as predicted. The monitoring data will also be used to validate and update geologic and reservoir simulation models. These models, being the primary method of forecasting the position, pressure, and saturation of the injected CO_2 within the Longleaf CCS Hub, will ultimately support and demonstrate the safe and permanent storage of CO_2 throughout the project. **Table 22** summarizes the well-based testing and monitoring activities at the Longleaf CCS Hub.

Longleaf CCS, LLC expects multiple sources of CO_2 from the Mobile, Alabama region, with additional sources to be added throughout the life of the project. As such, Longleaf CCS, LLC will continuously monitor the CO_2 stream with a gas chromatograph to ensure the physical and chemical characteristics of the CO_2 stream are as anticipated. Corrosion monitoring will occur quarterly by analyzing coupons of materials used to construct the CO_2 flowlines, long string casing, injecting tubing, well head and packer that are exposed to the CO_2 stream while injection is occurring.

Table 22: Summary of Testing and Monitoring Activities to be Conducted at the Longleaf CCS Hub.

Monitoring Activity/Test		Location	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
Fiber Optic / Seismic Monitoring	Distributed Acoustic Sensing (DAS)	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
	Distributed Temperature Sensing (DTS)	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
Pulsed Neutron Capture Log (PNC)		LL#1-4, IOB#1-5, AOB#1-2	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Mechanical Integrity Tests		LL#1-4, IOB#1-5	Once before injection	Annually	Annually
		AOB#1-2, UOB#1-4	Once before injection	Every 5yrs	Every 5yrs
Pressure Transient Test		LL#1-4	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Flow Profile Survey		LL#1-4	N/A	Every 5yrs	N/A
Bottomhole Pressure Monitoring		LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous surface read-out	Continuous surface read-out
Wellhead Pressure Monitoring	Tubing	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
	Annulus	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
Injection Rate and Volume Monitoring		LL#1-4	N/A	Continuous	N/A
Fluid Sampling		LL#1-4	Once during well construction	N/A	N/A
		AOB#1-2	At least 3 sampling events prior to injection	Quarterly for first yr; Annually thereafter	Annually
		UOB#1-4, All Shallow Groundwater Wells (10)	At least 3 sampling events prior to injection	Annually	Annually

Longleaf CCS, LLC will use continuous recording devices to monitor the injection pressure, rate, and volume; the pressure of the annulus between the long string casing; and the annulus fluid volume added. The downhole annulus pressure will be maintained at a pressure greater than the operating injection pressure during periods of injection. Fiber optic cable installed on the outside of the long string casing for all injection, in-zone monitoring, and above-zone monitoring wells will conduct continuous geophysical monitoring through distributed acoustic sensing (DAS) and distributed temperature sensing (DTS).

Longleaf CCS, LLC will conduct an annulus pressure test in all injection and in-zone monitoring wells annually to confirm mechanical integrity. DTS will occur continuously, and a temperature log will be run 3 years after injection begins and every 5 years thereafter in conjunction with PNC logging. Longleaf CCS, LLC will perform pressure falloff tests in all injection wells once before injection begins, 3 years after injection begins, and every 5 years thereafter in order to verify that the injection zone and pressure are responding as predicted.

Longleaf CCS, LLC will conduct fluid sampling and geochemistry testing in above-zone, deep USDW, and shallow groundwater monitoring wells to detect fugitive CO_2 and ensure USDWs are protected. Longleaf CCS, LLC chose the locations for above-zone and deep USDW monitoring wells based on the expected pressure and CO_2 plume development.

Longleaf CCS, LLC will utilize direct and indirect methods to track the extent of the pressure and CO_2 plume throughout the life of the project. Continuous downhole pressure monitoring will be performed in all injection wells and in-zone and above-zone monitoring wells with real-time surface read-out capabilities. Indirect CO_2 plume monitoring will occur using PNC logs and VSPs in conjunction with DAS to monitor formation fluid saturations (including the presence of CO_2) and track the movement of the CO_2 plume. These monitoring data will allow Longleaf CCS, LLC to ensure the injection zone pressure and CO_2 plume are behaving as expected and validate the reservoir model with real pressure and saturation data.

E.5 Injection Well Plugging

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

After the 30-year injection period, the injection wells will be plugged or converted to monitoring wells to ensure containment of the CO_2 in the injection zone. Upon completion of operations, the final bottom-hole pressure of the injection wells will be measured, and a buffered fluid (brine) will be used to flush and fill the wells to maintain pressure control. The injection tubing strings, packers, and gauges will be removed from the wells. The mechanical integrity of the wells will be determined to ensure no communication has been established between the injection zone and the USDWs or ground surface (per **40 CFR 146.92**). Finally, the entire wellbore will then be filled with cement, from the total depth to surface. CO_2 resistant cement will be squeezed into the perforations to seal and fill the wellbore up to the Marine Tuscaloosa Shale. The remaining wellbore will be filled with standard cement to surface. The casing will then be cut at least 5 feet below ground level and sealed with a welded steel plate.

E.6 Post-Injection Site Care (PISC) and Site Closure

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

The Post-Injection Site Care (PISC) timeframe will begin when all CO_2 injection ceases and ends with site closure. Longleaf CCS, LLC proposes a 20-year PISC timeframe based on results from computational modeling as discussed in the *AoR and Corrective Action Plan* as well as the *Post-Injection Site Care and Site Closure Plan*. Per **40 CFR 146.93(b),** Longleaf CCS, LLC will monitor the project site for CO_2 plume movement and pressure fall-off to demonstrate non-endangerment of USDWs throughout the PISC timeframe. The *Post-Injection Site Care and Site Closure Plan* describes the post-injection modeling that was completed to determine the pressure differential, position of the CO_2 plume, and prediction of CO_2 migration. Longleaf CCS, LLC also provides information required under **40 CFR 146.93(c)** to justify a 20-year PISC timeframe based on available modeling data. Additionally, the plan provides a detailed description of the post-injection monitoring plan and the site-closure activities. The numerical reservoir model used for calculating the AoR was also used for the PISC and site-closure analysis.

The predicted positions of the CO_2 storage zone and pressure front at the end of 30 years of injection and 20 years post-injection were simulated in the model. The simulation indicates that the CO_2 plume would remain within 2.3 miles from LL#1 at the time of site closure. Most of the CO_2 mass is concentrated around the four injection wells with some CO_2 extending outward from the injection wells, primarily in the in the up-dip directions to the northwest, southwest, and southeast. Based on the model, it is estimated that there is not sufficient hydrostatic pressure in the injection zone to push fluids into or interact with the lowermost USDW, which is the Chickasawhay formation.

Following the cessation of injection, some of the injection wells may be converted to monitoring wells to contribute to the collection of data as part of the Longleaf CCS, LLC monitoring program. The post-injection phase will include monitoring for gas leaks in the wellheads and valves, external mechanical well integrity testing, groundwater sampling, direct pressure and temperature measurements, indirect and direct plume tracking, surface and near surface CO_2 leak monitoring, and seismicity monitoring for induced and natural seismic events.

Once Longleaf CCS, LLC demonstrates plume and pressure stabilization, as well as non-endangerment of local USDWs, well plugging and abandonment of the remaining active injection wells will commence. Abandonment will be performed to preclude the movement of injection or formation fluids out of the storage complex. Prior to well plugging, the mechanical integrity of the wells will be verified by the distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) fiber optic systems emplaced in the monitoring wells. The well plugging and abandonment will follow the methodology described in the *Injection Well Plugging Plan*.

E.7 Emergency and Remedial Response

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

The *ERRP* details actions that Longleaf CCS, LLC will take to address movement of the injection fluid or formation fluid in a manner that may endanger a USDW during the construction, operation, or post-injection site care periods, pursuant to **40 CFR 146.82(a)(19) and 146.94(a)**. Examples of potential risks include: (1) injection or monitoring well integrity failure, (2) injection well monitoring and/or surface equipment failure, (3) natural disaster, (4) fluid leakage into a USDW, (5) CO_2 leakage to USDW or land surface, or (6) an induced seismic event. In the case of one of the listed risks, site personnel, project personnel, and local authorities will be relied upon to implement this *ERRP*. Longleaf CCS, LLC will communicate to the public any major emergency, as described in the *ERRP*, to ensure that the public understands what happened and whether there are any environmental or safety implications. This will include a detailed description of what happened, any impacts to the environment or other local resources, how the event was investigated, what actions were taken, and the status of the remediation.

The emergency contact list in Appendix B of the ERRP will be updated annually at a minimum, and the *ERRP* will be reviewed at least once every five years following its approval as well as within one year of an area of review (AoR) reevaluation and following any significant changes to the injection process or the injection facility or an emergency event. Periodic training will be provided to well operators, plant safety and environmental personnel, the operations manager, plant superintendent, and corporate communications to ensure that the responsible personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the *ERRP*.

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